AMERICAN ENERGY SECURITY

BUILDING A BRIDGE TO ENERGY INDEPENDENCE AND TO A SUSTAINABLE ENERGY FUTURE

The Southern States Energy Board
Norcross, Georgia

July 2006

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

APPENDICES

LIST OF TABLES

LIST OF TABLES
(Continued)

LIST OF TABLES
(Continued)

LIST OF FIGURES

LIST OF FIGURES
(Continued)

LIST OF FIGURES
(Continued)

LIST OF FIGURES
(Continued)

PREFACE

This report summarizes the findings of a national initiative led by the Southern States Energy Board (SSEB), an interstate organization of 16 states and two territories whose members are governors and state legislators, with a federal representative appointed by the U.S. President. The analysis and recommendations developed by the SSEB study team focused on the rapid development of an alternative oil and liquid fuels production base in America utilizing our vast domestic resources that include coal, oil shale, and biomass to achieve U.S. energy security and independence (ESI). The report also emphasizes the importance of increased transportation fuel efficiency, sensible energy conservation, and improved domestic enhanced oil recovery programs using carbon dioxide injection.

The American Energy Security Study has been guided by an expert Executive Panel comprised of representatives from the Southern States Energy Board, the U.S. Department of Energy-Naval Petroleum and Oil Shale Reserves, Peabody Energy, the Army National Automotive Center, EnviRes LLC, the U.S. Department of Defense, the University of Kentucky, Mitretek Systems, Management Information Services, Inc., General*Bioenergy, Augusta Systems, and A. J. Mayer International. Primary consultants for the study were Management Information Services, Inc., A. J. Mayer International, General*BioEnergy, MitreTek Systems, Inc., the DOE-Naval Petroleum and Oil Shale Reserves oil shale consulting team under Anton Dammer, and Augusta Systems, Inc. Other participants in the study included Robert Addington, Kenneth Nemeth, Randy Randol, J. Edward Sheridan, Frederick Palmer, Ari Geertsema, Joe Regnery, Sherry Tucker, Khosrow Biglarbigi, James Bunger, James Cobb, and Gerald Weisenfluh.

These experts from industry, government, and academia have spent the last 12 months developing this plan, including a portfolio of legislative recommendations. If enacted by Congress and by state legislatures, these initiatives will become America’s first comprehensive energy plan to eliminate dependence on foreign oil.

To date, funding for the study has been provided by the Commonwealth of Kentucky, the U.S. Army National Automotive Center, the Association of American Railroads, Rentech, Inc., EnviRes LLC, the Southern States Energy Board, Peabody Energy, and the National Mining Association. Consulting services and information from extensive ongoing studies of U.S. oil shale have been provided by the U.S. Department of Energy-Naval Petroleum and Oil Shale Reserves.

We would like to thank everyone who participated in this important body of work.

EXECUTIVE SUMMARY

The American Energy Security Study is a national initiative led by the Southern States Energy Board (SSEB). The study develops a comprehensive plan for the United States to establish energy security and independence through the production of alternative oil and liquid transportation fuels from its vast domestic resources, including coal, biomass, and oil shale. The plan also emphasizes the need for improved domestic enhanced oil recovery programs using carbon dioxide injection and storage, increased voluntary transportation fuel efficiency, and sensible energy conservation. Throughout this report the term oil means crude oil or both crude oil and refined transportation fuels.

This study is a leadership initiative, designed to (1) establish an ambitious goal for the nation, (2) broadly frame a plan for success, (3) model the benefits of achievement and the great costs of inaction, and (4) formulate a package of specific federal, state and local recommendations including legislation to support the plan.. It does not purport to offer detailed solutions to the many challenges that will be encountered if America demonstrates the will to pursue this bold course of action. We are confident, however, that the stated mission *can* be accomplished if national will is strong enough.

Another purpose of the study is to bring better awareness to the American people, industry, the financial community, the media, governors, and legislators and political leadership at the national, state and local levels. America now faces a crisis of historic proportion: a liquid transportation fuels crisis. Oil, the lifeblood of our economy, is in increasingly short supply and oil and derivative product prices have recently soared to record levels. Yet few realize the great possibilities that lie within our borders:

- America has the world's largest alternative liquid fuels resource base of coal, biomass, and oil shale to substitute for conventional oil imports.
- Exciting technologies are available to harness these resources in an environmentally respectful and economically rewarding manner.
- Capital is available in unprecedented quantities for good projects.

These enviable building blocks can be assembled to substantially reduce and ultimately eliminate our dependence on foreign oil. In support, federal and state legislatures are encouraged to champion and enact the legislative measures called for in this study without further delay.

Embarking on a national mission to achieve energy security and move toward liquid fuels independence will not only reduce risk and lower oil prices and oil price volatility, it also will facilitate an industrial boom, create millions of jobs, foster new technology, enhance economic growth, help to eliminate the trade and budget deficits, ensure affordable energy for citizens and strategic fuels for the military, and establish a reliable domestic energy base on which to rebuild U.S. industries to be globally competitive.

Following is an abbreviated presentation of key facts, figures, projections, plans, observations, and analyses contained in the American Energy Security Study. Recommendations for federal, state and local incentives including legislation are also provided. Substantial support information is contained in the main body of the American Energy Security Study report, available on CD ROM and on our website: www.AmericanEnergySecurity.org.

THE CHALLENGE BEFORE US

America is at a crossroads. We can either choose to produce our own transportation fuels utilizing vast domestic resources to secure our own destiny, or we can continue to rely on expensive foreign oil from unstable sources. The choice is clear, and this report shows how this choice can and must be implemented. The essential elements for success are:

- A national commitment to immediately begin to implement all initiatives without delay
- Federal incentives that build upon the legislation enacted in the last two years, including the Energy Policy Act of 2005. Many of the recommendations need to be enacted during the remaining days of the 109th Congress in order for startup in 2007
- State and local incentives that complement the federal incentives
- Mobilization of the private capital required to build the needed facilities and infrastructure

The Costs and Risks of U.S. Oil Import Dependence

The study finds that this nation faces four serious oil-related risks:

- Excessive dependence on the OPEC cartel and on other unstable foreign oil suppliers
- Conventional petroleum supplies are not meeting dramatic increases in world demand
- Rapidly increasing global competition for oil from China, India, and other nations
- Supply disruptions from natural disasters, political causes, and potential terrorism

Tightening oil markets and record high prices have brought U.S oil vulnerability back into focus, and hurricane Katrina demonstrated how quickly oil supply disruptions can impact the country. More serious supply disruptions will likely occur in the future, caused again by natural forces like Katrina, or by terrorist acts, or purposeful rationing by the OPEC cartel and rogue nations such as Iran and Venezuela.

New oil discoveries are not keeping up with historic world increases in oil consumption, driven by the U.S., China and India. The U.S. faces a serious liquid transportation fuels crisis. To mitigate the unprecedented risks and to provide for future economic prosperity and national security, the U.S. must reduce its growing dependence on foreign oil suppliers by producing its own liquid fuels from domestic sources. While some refer to the oil risks and challenges the nation faces as an "energy crisis," this is misleading. What we face is the ominous prospect of crippling oil and liquid fuel shortages and soaring, volatile prices.

America imports about 60% of the oil it consumes. In 2005 U.S. oil imports totaled approximately $250 billion, or $680 million per day. That figure is fast approaching $1.0 billion per day. The direct and indirect costs to the U.S. economy have been estimated to total about $300 billion per year. U.S. dependence on crude oil and refined product imports imposes an enormous economic penalty that is not fully reflected in the retail price of gasoline, diesel fuel, and jet fuel. It is the penalty of lost jobs, drained investment capital, and an increased national defense burden. The U.S. cannot pay this $300 billion (and rising) cost forever. When all of these elements are considered, they raise the "real" price of imported oil to well over $100 per barrel of crude. This translates into a pump price for gasoline of over $5.00 per gallon, or nearly $100 to fill an average gas tank.

There are at least four elements that comprise this burden:

- Military expenditures specifically tied to defending Persian Gulf oil
- The cost of lost employment and investment resulting from the diversion of financial resources
- The cost of the periodic "oil shocks" and disruptions the nation has experienced (and will likely continue to experience)
- The erosion of the U.S. industrial base

A growing number of oil industry experts predict that world crude oil production will "peak" by 2020, or sooner. As the "peak" approaches, world supplies will begin failing to meet world demand, and the shortfall will grow with time. This study forecasts that at oil peaking, oil prices would immediately increase by about 150 percent, and continue to rise as the gap between supply and demand widens. Many oil market specialists contend that if a peak occurs, oil prices could increase much more than 150 percent. Clearly, if oil peaks and the U.S. is unprepared, the economic impact will be catastrophic. Even without peaking, continuing tight markets represent risk.

The American Energy Security Study estimates that if oil peaks in 2010, and aggressive domestic alternative fuels production programs are not implemented, over the period 2010-2020 the U.S. economy will lose about:

- $4.6 trillion in GDP
- 40 million job years of employment
- $1.3 billion in federal, state, and local government tax revenues

We estimate that if oil peaks in 2020 and no crash programs are implemented, over the period 2020-2030 the U.S. economy will lose about:

- $13 trillion in GDP
- 100 million job years of employment
- $4 trillion in federal, state, and local government tax revenues

The American Energy Security Study shows that immediate implementation of "crash" programs to ramp up production of domestic alternative liquid transportation fuels is the only way to insure against peak oil. The potential economic costs and consequences of doing nothing in preparation far exceed the costs of implementing crash programs. Our economic analysis demonstrates that even if world oil production does not peak between now and 2030, implementing crash programs will have a very positive impact on the economy by increasing economic activity, reducing the trade deficit, and lowering prices for transportation fuels.

The economic, national security, and environmental advantages of establishing a thriving domestic alternative liquid fuels industry vastly outweigh the development costs. In contrast, doing little or nothing subjects America to energy supply disruptions and to potentially severe economic consequences and national security risks.

National Security Implications

The U.S. military uses between 300,000 and 400,000 barrels of fuel each day to defend our nation (primarily jet fuel and some diesel). The dramatic run up in the cost of fuel, and the elevated risk of supply disruptions and shortages, threatens military readiness.

Protecting oil shipping and transportation corridors and production facilities abroad requires a massive U.S. military presence in the Middle East, costing billions of taxpayer dollars and stretching military resources. As competition for oil intensifies, international confrontation and conflict will become more likely as nations attempt to secure needed oil supplies. Further, U.S. funds tendered to purchase imported oil are sometimes used to fund terrorist organizations.

Military leadership recognizes that national security is seriously threatened by dependence on imported oil. That is why the Department of Defense is so actively championing the rapid development of domestic sources of reliable, cost-competitive, high-performance, low emissions alternative fuels for military vehicles, aircraft, and ships.

A PLAN TO BREAK THE CHAINS OF DEPENDENCE

The American Energy Security (AES) Study shows that the United States can eliminate dependence on oil imports entirely by 2030. It establishes a bold plan to replace approximately five percent of imported oil each year for 20 years, beginning in 2010 (see Figure EX-1 below). Assuming aggressive implementation beginning in 2007, under the SSEB American Energy Security initiatives domestic liquid fuels production and transportation efficiency savings begin gradually after 2010 and ramp up to produce most of the nation's liquid fuels requirements by 2030 (see Figure EX-2).

U.S alternative resources of coal, biomass and oil shale are the largest in the world, rivaling conventional world oil resources. This tremendous resource base serves as the foundation of our plan. Numerous low and near-zero emissions alternative liquid fuel plants will need to be brought online each year to manufacture clean fuels from America's vast domestic resource endowment. Substantial improvements in transportation energy efficiency will also be necessary. Clearly, an enormous effort will be required from industry, the financial community, government, and the American people. **Though a very ambitious goal, the study shows how it can be achieved, why it must be achieved, and the tremendous economic, national security and environmental benefits that will result beginning almost immediately**.

To establish U.S. energy security and independence by 2030 all feasible supply and demand options must be aggressively pursued. There is no single answer:

- Transportation energy efficiency improvements are important but, by themselves, can contribute only a small portion of the required solution.
- Renewable biomass fuels are a critical part of the portfolio of required initiatives, but can produce less than one-fourth of the required liquid fuels.
- CTL, oil shale, and EOR will all contribute substantially, and all three technologies must be aggressively deployed.

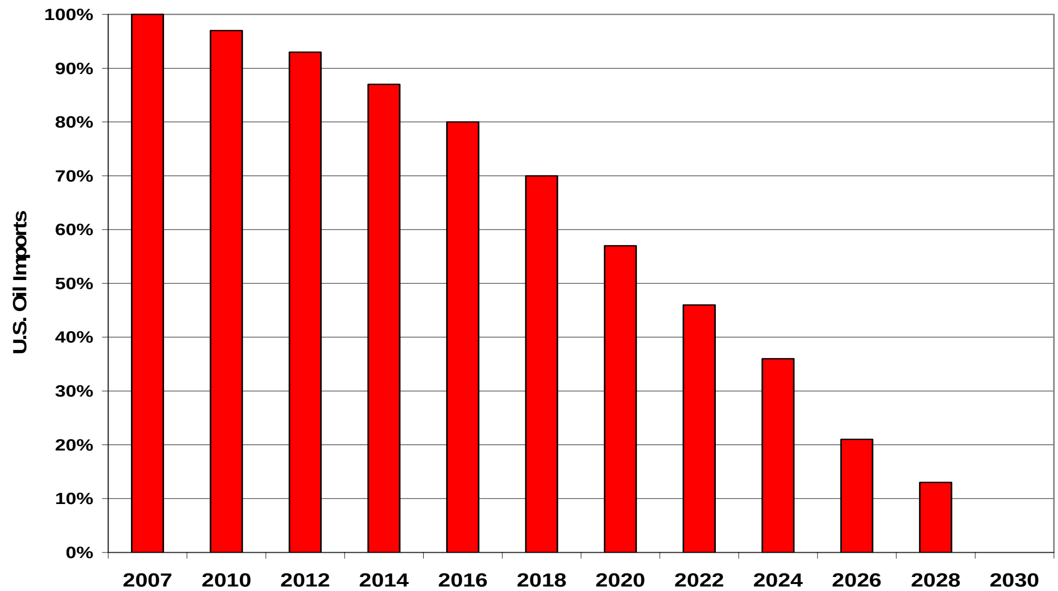
All of the options presented here are technologically feasible, rely on domestic U.S. resources, and are capable of attaining the goals established over the next two decades. The resource assessments, technology assessments, costs, and forecasts were developed by respected experts in their fields.

Figure EX-2 presents a visual portrayal of how America's most abundant liquids fuels resources can be responsibly harvested to supplement U.S. conventional oil output, reducing and ultimately eliminating the projected oil import gap. Utilizing clean production technologies, aggressive development programs in coal-to-liquids (CTL), various biomass-to-liquid fuels processes, oil shale extraction, and CO_2 enhanced oil recovery (EOR), will all play a critical role. Voluntary transportation efficiency and conservation (TE&C) programs that reduce consumption also will be necessary.

Assuming initiation in 2007, the programs begin to displace a small portion of U.S. oil imports after 2010. As the programs ramp up over the two decades, they begin to replace a larger portion of U.S. oil imports every year:

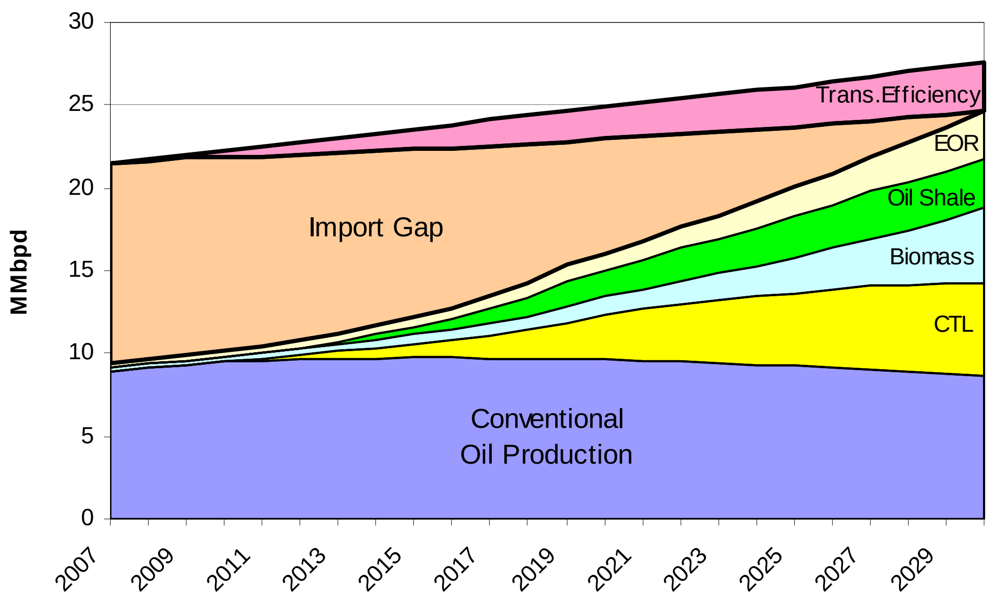
- By 2015, the AES initiatives replace about 16 percent of U.S. oil imports.
- By 2020, they replace about 43 percent of U.S. oil imports.
- By 2025, they replace nearly three-quarters of U.S. oil imports.
- By 2030, they replace all of U.S. oil imports.

Figure EX-1: Reduction in U.S. Oil Imports Resulting From the AES Initiatives



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure EX-2: The Path to U.S. Energy Security and Independence



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

It is important to note that time is of the essence. Implementation of the American Energy Security initiatives must begin no later than 2007, and delay is not an option. This study finds that, even with aggressive implementation of all of the initiatives starting next year, it will take at least a decade to begin significantly reducing U.S. oil imports, and well over two decades to achieve national energy security and independence. Any delay will leave the U.S. highly vulnerable to shortages, supply disruptions, high and volatile prices, and the catastrophic possiblity that world oil production may soon peak.

National Will and Partnership

Strong leadership will be required to achieve the goals stated in the American Energy Security Study. Political, business, and community leaders will be called on to inspire the time proven energy, ingenuity, and resolve of Americans in crisis—elevating *national will*. Our study assumes that leadership at all levels will create a new national mission, bringing Americans together behind the cause of oil security and independence, much as was done during World War II to achieve a crucial goal of similarly enormous proportions. Our hope is that many will rise up to this leadership challenge. The stakes could not be greater.

American partnerships will need to be strengthened between industry, government, and our communities. Industry sectors inclined to compete against each other will need to find common ground to work together in a cooperative spirit. The American people and local communities must be inspired to offer their patriotic support for new industries and businesses that manufacture the domestic alternative liquid fuels on which America's future depends. Though the challenges ahead are great, there will be bountiful benefits and opportunities created for all if we join together as a country to overcome foreign oil dependency.

Responsible Bridge to a Sustainable Energy Future

Technology offers great energy promise. One day it is likely that all of our energy needs will be met by renewable and sustainable resources. Fossil fuels, after all, are finite resources, and alternatives must ultimately be established. But this will take decades.

For now, fossil fuels are the lifeblood of our economy, our civilian transportation system, and our military. Developing reliable, clean domestic sources of fuels will ensure economic prosperity and an improving standard of living during the transition to a sustainable energy future.

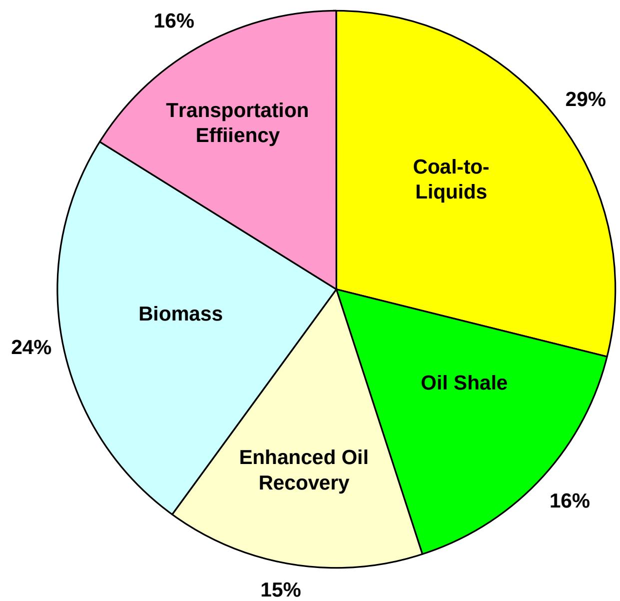
GENERAL FACTS AND FINDINGS

The United States can and should become energy secure and independent by 2030.

- The U.S. is endowed with the largest alternative oil resources in the world. This includes five hundred billion tons of coal (oil equivalent of approximately 750,000 billion barrels), the potential to sustain 1.3 billion tons of biomass collection/harvesting for liquid fuel production by 2030 (oil equivalent of approximately 4.5 million barrels per day to perpetuity), more than a trillion barrels of oil shale liquid fuels, and 80+ billion barrels of oil stranded in conventional reservoirs that are technically recoverable using CO_2 injection and sequestration to enhance oil recovery. These resources rival estimated worldwide conventional oil resources of 1-2 trillion barrels.

- The following graphic (Figure EX-3) shows the contribution projected for each alternative resource in 2030, as a percentage of total oil imports displaced. Transportation efficiency & conservation also contribute by reducing projected oil consumption. Note that coal-to-liquids is anticipated to carry the greatest load, and that renewable biomass and transportation efficiencies together account for 40% of the total.

Figure EX-3: Estimated Contributions of Each Resource to Eliminate U.S. Oil Imports in 2030



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

- Proven technologies are commercially available today to produce mass quantities of ultra-clean alternative liquid fuels from coal and biomass competitively at a profit in today's marketplace. Highly promising oil shale and biomass-to-fuel technologies are rapidly emerging.
- Commercial coal-to-liquid fuels (CTL) technologies have existed for decades. Sasol, a South African company, currently provides almost 30 percent of that country's liquid fuel needs through coal gasification and follow-up Fischer-Tropsch conversion of the syngas into premium, ultra-clean liquid fuels. It does so, profitably, in the open market. Sasol was created with support from government to decrease dependence on foreign oil. The company quickly outgrew its need for government

assistance and is highly profitable today. The U.S. can and should follow the Sasol model, which clearly demonstrates that it is not only possible but also highly profitable to rapidly ramp-up production of ultra-clean liquid fuels from domestic coal.

- Biomass derived liquids, specifically starch/grain base ethanol and biodiesel fuels, are already flowing into the U.S. marketplace in commercial volumes. With a mandate from Congress, corn/grain-based ethanol and biodiesel production are projected to continue to grow rapidly over the next few years. This study has identified three emerging biomass technologies expected to contribute on a much larger scale: cellulosic ethanol; biomass gasification with Fischer-Tropsch fuel synthesis, and pyrolysis.
- Several large scale oil shale recovery technologies are nearing the commercial stage: surface retorting of mined oil shale feedstocks, and in-situ processing and recovery of oil shale kerogen which is converted to oil. A good analog for U.S. oil shale is the success Alberta, Canada, has had developing its tar sands with new technology. Canada is now second only to Saudi Arabia in proven oil reserves and ninth in the world in annual oil production. This is a direct result of successful development of its tar sands. The driving force has been the Alberta government's decision to help promote and develop this vast alternative liquid fuel resource, and not giving up as methods and technologies were evolved to allow highly profitable oil recovery. Projections in this study indicate that the emerging oil shale technologies can be profitable in the very near-term.
- As part of this study, capital and operating cost estimates were assembled and/or prepared for coal-to-liquids plants, the principal emerging biomass technologies, oil shale operations, and CO_2 Enhanced Oil Recovery. Extensive work was done to prepare up-to-date cost estimates for 16 different CTL plant configurations. The viability-threshold price for CTL plants ranges from $35 to about $55 per crude equivalent barrel of oil, depending on the plant size, coal rank, and configuration. This translates to finished diesel fuel sales prices of $45.50 to $71.50 per barrel. Oil shale, biomass and CO_2 EOR costs are all comparable.
- Large combination carbon-to-liquids plants are envisioned that can process a varied blend of coal, biomass and oil shale derived feedstocks into high quality fuels. These combination plants first will gasify the carbon-bearing feedstocks and then combine the product syngases into liquid fuels using well established Fisher-Tropsch technology.
- Building near-zero emissions production facilities that will take the place of otherwise necessary new conventional refinery capacity, a substantial reduction in emissions will be realized. Gasification/Fischer-Tropsch plants, for example, can and will economically capture CO_2 and make it available for productive uses such as enhanced oil

recovery and storage. Because many of the new technologies will allow economic CO_2 capture, we see new these fuel production facilities changing the way CO_2 is viewed. With large CO_2 streams soon to be available at reasonable cost, many new applications will be developed to utilize and sequester this "strategic gas." Incentives to capture, utilize and store CO_2 are part of the AES plan, as set forth in "Policy Recommendations" below.

- Commercial success over the past 20 years with Enhanced Oil Recovery using CO_2 flooding suggests that American oil and gas production can be dramatically increased by this method. Miscible and immiscible CO_2 flooding can revitalize certain mature oil fields. In addition, CO_2 injection into coal seams and traditional natural gas formations is an emerging technology that will increase natural gas production. At present, limited availability of CO_2 supplies severely constrains this production enhancing technique. However, coal, oil shale, and biomass-to-liquids plants will produce and capture large quantities of CO_2, which can be sold to oil and gas producers for such enhanced recovery uses. Thus, the CO_2 generated by these plants can be put to a positive use, while at the same time permanently and safely storing it in reservoirs deep beneath the earth's surface.
- By producing environmentally superior transportation fuels from near-zero emissions plants, the United States can set an example for the world. Coal, biomass and oil shale derived liquid fuels produced from gasification and follow-up Fischer-Tropsch (FT) processing, for example, will produce ultra-clean, bio-degradable, essentially zero sulfur, low particulate and NO_x emissions diesel and jet fuels, having performance characteristics superior to their conventional distillate counterparts. Zero sulfur gasoline also can be produced. Increased performance from FT fuels translates to lower CO_2 emissions per mile traveled.
- In this study we assumed that, coincident with the crash substitute fuels programs, transportation fuel efficiency also will increase substantially by 2030. The gains likely from transportation efficiency and conservation reduce the forecast for overall U.S. petroleum requirements. Vehicles and light-duty trucks offer the greatest promise for significant consumption savings. Following Europe's lead, a shift to diesel and Fischer-Tropsch zero sulfur diesel is anticipated. Diesel vehicles are typically 20 to 40% more fuel efficient than gasoline counterparts, reducing not only fuel consumption but also emissions. Diesel hybrids can approximately double the efficiency.
- Increases in coal and oil shale mining will be accomplished responsibly. Contrary to common belief, existing mining laws are very tough, strictly prohibiting pollution. In addition, remining of previously abandoned mined areas and mine reforestation programs are having very positive environmental results. The study encourages mining regulatory authorities and mining companies to advance remining and

reforestation programs. Experimental reforestation projects have demonstrated that tree growth rates can be dramatically increased from normal rates experienced in nature by preparing mined ground properly before planting. Young, fast growing trees capture greater volumes of CO_2. The new soil preparation techniques provide greater moisture collection for the trees, and reduce water runoff from mine sites. Expanding programs that incorporate accelerated-tree growth into mine reclamation plans show great promise for reestablishing forests, increasing property values of mined land, providing a dynamic new source of arbor fuel crops and wood products resources, and capturing CO_2. Reforestation is a natural form of CO_2 capture and storage.

- The jump-starting of a new domestic alternative liquid fuels manufacturing industry will require tremendous investment of private capital. The risks associated with such investment are perceived to be substantial, given the historic volatility of oil prices. The most significant contribution that federal and state governments can make is develop programs that lower the risk profile of alternative fuel projects. By mitigating risk, project sponsors, backed by large pools of private capital, will rush to build alternative liquid fuels plants in all 50 U.S. states, strengthening economies, creating millions of jobs, stabilizing fuel prices, and lessening our dependence on foreign oil. Tax and fiscal incentives also are recommended to help catalyze development. The AES study has developed a portfolio of policy recommendations, outlined at the end of this executive summary, that can ensure a stable, long term, liquid fuels industry.
- America has the natural resources, the financial resources, and the technologies to achieve U.S. energy security, freedom, and independence. All that is required is *national will*.

Alternative Energy Farms

Tremendous opportunities now exist to develop multi-source energy complexes that co-produce liquid fuels, natural gas substitutes, hydrogen, electric power, process heat, agricultural fertilizer and petrochemical feedstocks. Some are calling these facilities of the future “Alternative Energy Farms” or “AEFs.” They will include various integrated combinations of alternative energy production units, such as:

- Coal-to-liquids/gas/electricity/fertilizers/hydrogen/chemicals/steam (including co-feed with biomass)
- Biomass-to-liquids/gas/electricity/ fertilizers/hydrogen/chemicals/steam
- Oil shale-to-liquids/ gas/electricity/chemicals/steam

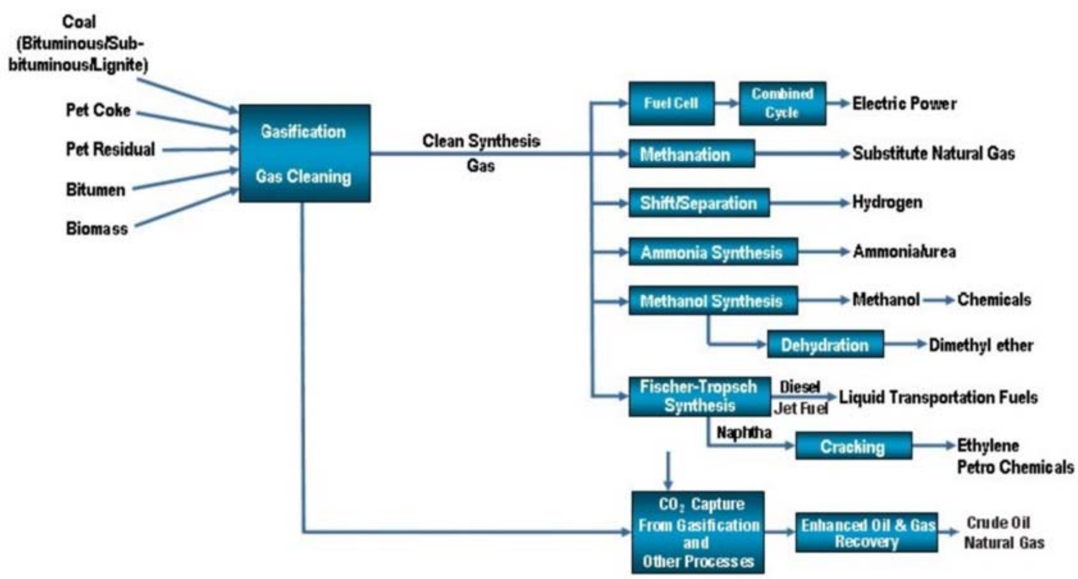
Wind, solar, and hydro modules also are possible, depending on site locations. Siting some AEFs beside oil refineries makes sense because AEF’s can supply refineries with competitively priced ultra-clean diesel and jet fuel, gasoline, and naphtha for blending and marketing, as well as electricity, process heat/steam, and hydrogen from near-zero emissions production facilities. The hydrogen economy will need economic production facilities distributed across the country—AEFs and stand-alone coal-to-liquids and biomass-to-liquids plants can serve this purpose.

Energy Farms will more fully and efficiently utilize local natural and waste resources, process heat, infrastructure, product blends, manpower, technology, land, and capital. Resulting synergies can significantly improve resource utilization and efficiencies, thereby lowering production costs. Environmental benefits will abound.

One of the many possible benefits of an AEF is that excess heat recovered from coal-to-liquids and other operations can greatly reduce the cost of co-producing ethanol, biodiesel, and other heat intensive processes. By capturing CO_2 from an entire AEF complex, and making it available for productive use (such as the enhancement of oil and gas production) and ultimate storage, an AEF can approach zero emissions.

The following diagram (Figure EX-4) highlights the broad array of products that are possible by gasifying various carbon resources, including biomass and coal. Gasification plants are anticipated to serve as the foundation of many Alternative Energy Farms. The age of near-zero emissions carbon gasification is believed to have arrived.

Figure EX-4
The Many Products Possible from Gasification



ECONOMIC IMPACT

Achieving U.S. energy security and independence will require a paradigm shift resulting in massive, continuing, decades-long effort by the private and public sectors. Thus, appropriate fiscal, regulatory, and institutional support mechanisms must be put in place and remain in effect for about two decades to achieve stated goals. The rewards will be great.

This study demonstrates that embarking on a national mission to achieve liquid transportation fuels independence will substantially reduce economic and national security risks and lower oil prices and oil price volatility. It will also facilitate a U.S. industrial rebirth.

<u>The American Energy Security plan will facilitate an industrial boom</u>. It will create millions of jobs, foster new technology, enhance economic growth, help eliminate the trade and budget deficits, and establish a reliable domestic energy base upon which to rebuild U.S. industries to be globally competitive – see Table EX-1.

By 2020, here are some of the annual benefits generate by the AES initiatives (2005 dollars):

- Domestic alternative liquid fuel production plus transportation efficiency savings of 8.4 million barrels per day
- New investments of $100 billion
- Nearly 200 billion dollars in increased industry sales
- Nearly 900,000 new jobs
- $8 billion in profits
- Nearly $60 billion in increased federal, state, and local government tax revenues.
- A reduction of a quarter trillion dollars in the U.S. trade deficit

By 2030, these annual benefits are projected to increase to (2005 dollars):

- Domestic alternative liquid fuel production plus transportation efficiency savings of 19 million barrels per day
- New investments of nearly $200 billion
- One-third of a trillion dollars in increased industry sales
- More than 1.4 million new jobs
- $14 billion in profits
- Nearly $100 billion in increased federal, state, and local government tax revenues.
- A reduction of over $600 billion in the U.S. trade deficit

<u>The American Energy Security plan will revitalize major U.S. industries</u>. Major industry beneficiaries will include technology providers; construction; petroleum and coal products; machinery; mining; professional, scientific, and technical services; primary metals; chemicals; oil and gas; motor vehicles; fabricated metal products; forestry; farming; and related industries.

Table EX-1: Summary of the Economic Impacts of the AES Initiatives
(dollars in billions of 2005 dollars)

	2020	**2030**
Capital Expenditures	$51	$53
Operating and Maintenance Expenditures	$49	$132
Total Industry Sales Generated	$182	$332
Jobs Created	894,000	1,403,000
Industry Profits	$8	$14
Federal, State, and Local Government Tax Revenues Generated	$56	$94
Reduction in U.S. Trade Deficit	$250	$625

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

American Energy Security initiatives will create an especially robust labor market and greatly enhanced employment opportunities in many industries and in professional and skilled occupations such as chemical, mechanical, electronics, petroleum, and industrial engineering; electricians; sheet metal workers; geoscientists; computer software specialists; skilled refinery personnel; tool and die makers; computer controlled machine tool operators; industrial machinery mechanics; electricians; oil and gas field professionals and technicians; machinists; engineering managers, electronics technicians; carpenters; welders; plumbers; and others.

In 2025 the SSEB American Energy Security initiatives will produce or save nearly six times the amount of oil that the U.S. would be importing from the Middle East in that year. In fact, one of the options alone, coal-to-liquids, would be providing twice the amount of liquid fuels required to make the U.S. independent of oil imports from the Middle East in 2025. And each of the other initiatives would individually be producing or saving about enough liquid fuels to make the U.S. independent of oil imports from the Middle East.

With the American Energy Security initiatives, *by 2030 U.S. domestic resources will be providing nearly 60 percent of total U.S. liquid fuels requirements,* Coal-to-liquids will be providing about one-fifth of U.S. liquid fuels requirements, and biomass more than one-sixth. In essence, the structure of U.S. liquid fuels supply will be radically changed, with substitute fuels production from domestic sources replacing oil imports.

Economic and Jobs Benefits of the American Energy Security Program

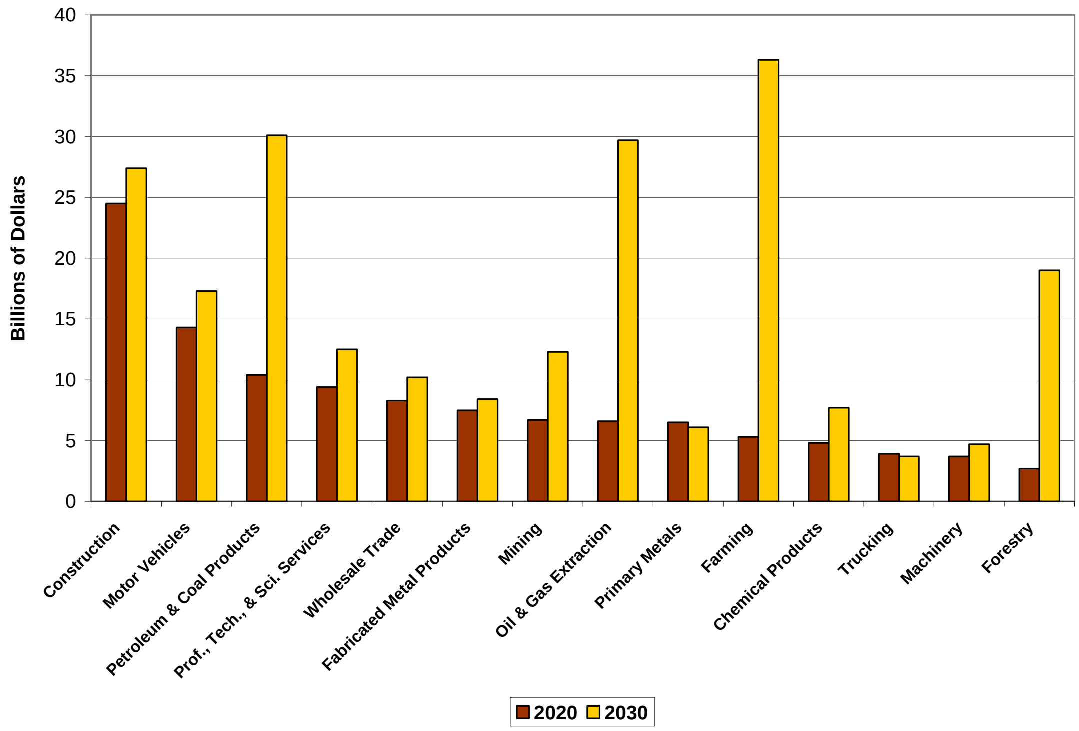
Not surprisingly, industry sales are dramatically increased by the AES initiatives. In 2020 construction realizes the greatest increases, and by 2030 farming is realizing the greatest sales gains (see Figure EX-5). The AES initiatives are also a powerful engine for job creation.

To highlight job growth we disaggregated the employment generated by the AES initiatives into occupations and skills for selected occupations in 2020 and 2030 (see Figure EX-6). The jobs generated are concentrated in fields related to the construction, energy, and industrial sectors. **Clearly, the plan will revitalize large sections of U.S. industry and create disproportionately large numbers of jobs for professional, technical, and skilled occupations** such as civil engineers, electricians, geoscientists, machinists, mechanical engineers, petroleum system and refinery operators, welders, and software engineers.

These requirements will create an especially robust labor market and greatly enhanced employment opportunities in many industries and in professional and skilled occupations such as chemical, mechanical, electronics, petroleum, and industrial engineers; electricians; sheet metal workers; geoscientists; computer software engineers; skilled refinery personnel; tool and die makers; computer controlled machine tool operators; industrial machinery mechanics; electricians; oil and gas field technicians, machinists, engineering managers, electronics technicians, carpenters; welders; and others. However, it also is important to note that millions of jobs will be created at all skill levels for occupations such as laborers, farm workers, truck drivers, security guards, managers and administrators, secretaries, clerks, service workers, and so forth. Workers at all levels will greatly benefit – see Figure EX-7.

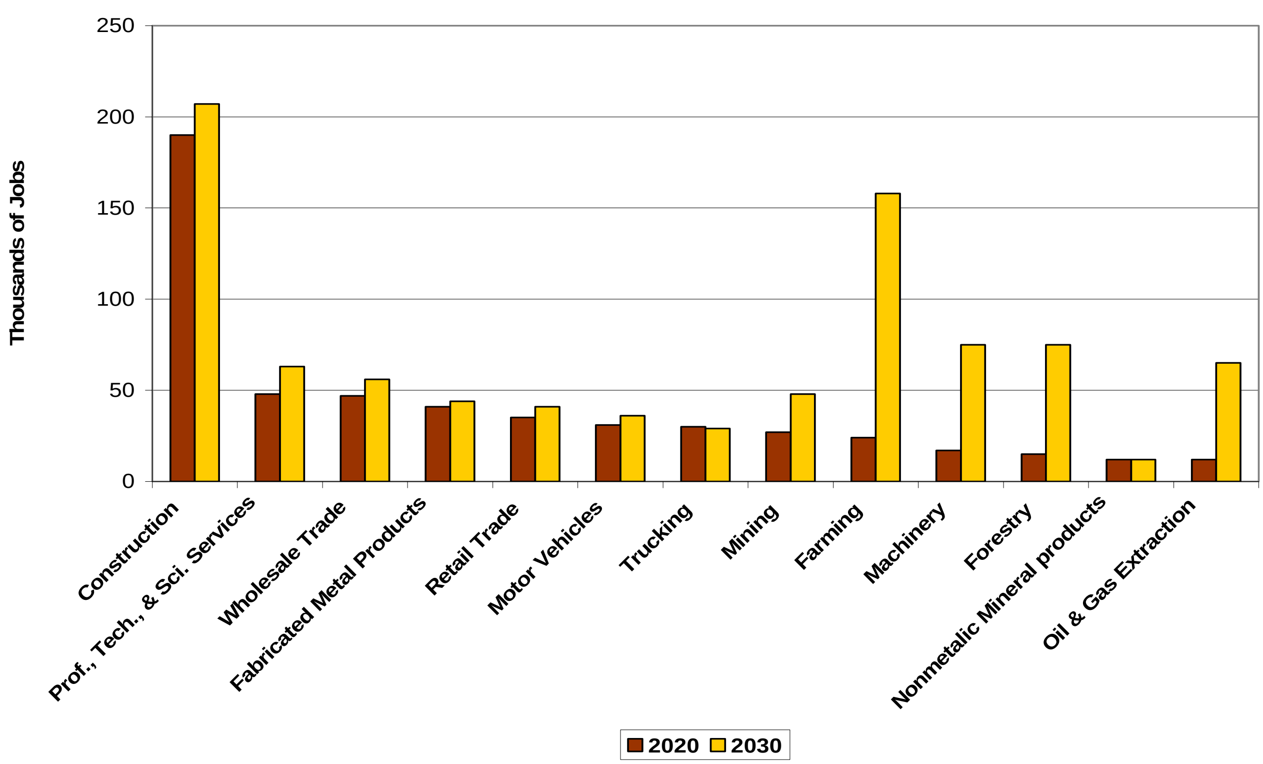
Clearly, the economic advantages of establishing a thriving domestic alternative liquid transportation fuels industry vastly outweigh the development costs. In contrast, doing little or nothing subjects the U.S. to energy supply disruptions and to potentially severe economic consequences. The national security and environmental benefits make the AES plan even more compelling.

Figure EX-5: Sales Created in Select Industries in 2020 and 2030



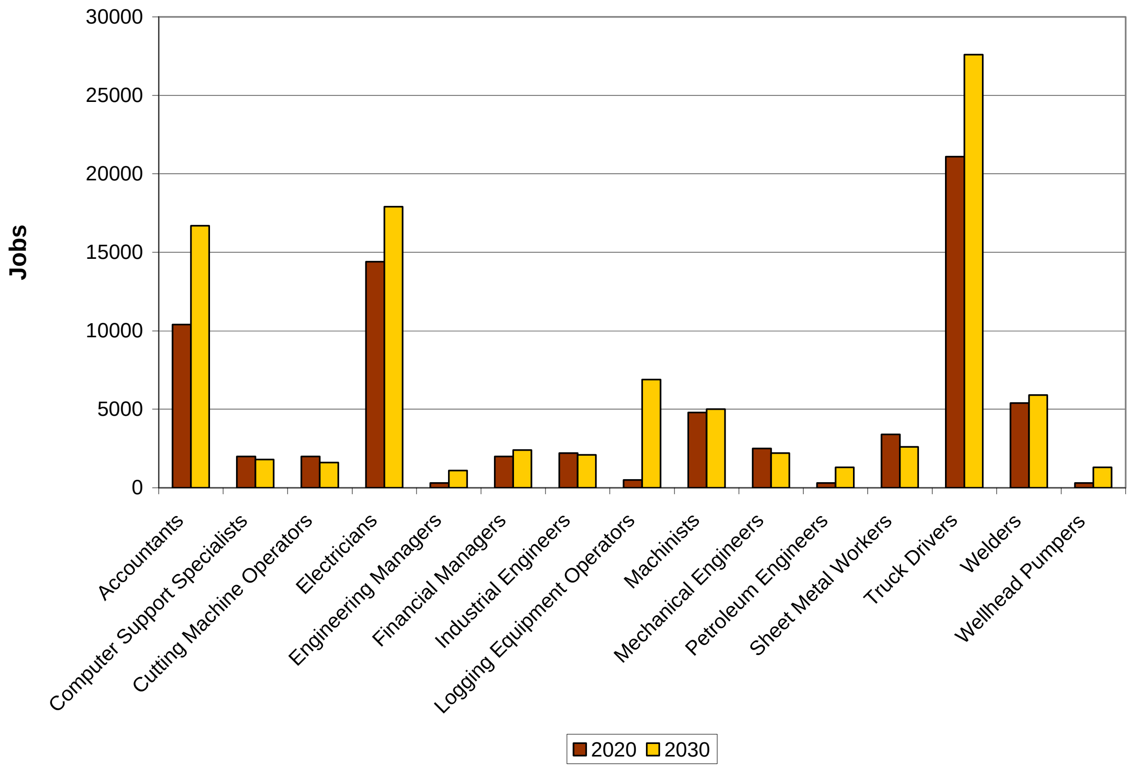
Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure EX-6: Jobs Created in Select Industries in 2020 and 2030



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure EX-7: Jobs Created for Select Occupations by the Initiatives in 2020 and 2030



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

POLICY RECOMMENDATIONS

Some argue that the free markets will provide solutions to our liquid fuels crisis. Unfortunately, the oil markets are anything but free. They are controlled by a cartel of oil producing nations (many unfriendly to the U.S.) and by the multinational oil companies. Both groups are making record profits under current market conditions. Both have tremendous market and political influence, and are expected to use this influence to prevent competitive alternative oil and liquid fuels production from developing significant market share.

Government policies are clearly necessary to ensure against market manipulation and other predatory business practices by OPEC and the multinationals. These practices create a risky business environment, and will prevent alternative oil and liquid transportation fuel production from developing to any significant degree.

SSEB recommends that the following private capital formation policies be implemented to encourage the private sector to step forward on a massive scale. The specific fiscal, tax, legislative, and regulatory recommendations presented below are designed to encourage private sector commitments to build alternative liquid fuel plants that will provide for America's security and economic and energy future. It is a logical response to the liquid fuels "crisis" that Department of Energy Secretary Bodman recognizes we now face.

Federal Fiscal, Tax, Legislative, and Regulatory Recommendations

Two bills have been introduced that incorporate many of the AES Study recommendations. Copies of these bills are available on the American Energy Security website under the "Legislative Initiatives" heading at www.AmericanEnergySecurity.org

S. 3325- The Coal-to-Liquid Fuel Promotion Act of 2006 introduced by Sen Jim Bunning (R-KY), Sen Barack Obama(D-IL), Sen Richard Lugar(R-IN), Sen Conrad Burns(R-MT), and Sen Mark Pryor(D-AR) on May 26, 2006. Co-sponsors include Sen Lisa Murkowski (R-AK), Sen Kit Bond (R-MO), Sen Mel Martinez (R-FL), and Sen Craig Thomas (R-WY).

H.R. 5653- The Investment in American Energy Independence Act of 2006 introduced by Rep. Ron Lewis (R-KY) on June 20, 2006. Co-sponsors include Rep. Harold Rogers (R-KY) and Rep. Chip Pickering (R-MS).

References to the relevant section in these bills are provided.

1. Extend the $0.50 Per Gallon Alternative Liquid Fuels Excise Tax Credit

The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users, SAFETEA-LU 2005 extension, provides a $0.50 per gallon excise tax credit for certain alternative liquid fuels, including coal-to-liquids products. This incentive is set to expire in 2009, before any major new alternative liquid fuel plants can come online, and its extension through 2020 is required. See S. 3325, Section 8; H.R. 5653, Section 4.

2. Provide Accelerated Cost Recovery to Alternative Fuel Plant Owners

Authorization for 100 percent expensing in the year of outlay for any alternative liquid fuel plant begun by 2020 will provide a substantial tax incentive to build alternative fuels manufacturing capacity. Providing for a 20% investment tax credit for the amount that is not expensed will improve the financial viability of projects. See S. 3325, Sections 6 & 7; H.R. 5653, Sections 2 & 3.

3. Incentivize the Refining of Alternative Liquid Fuels

We recommend extension of the now temporary expensing allowance for equipment used in refining to 100 percent of any required additions to existing refineries needed to handle domestic alternative liquid fuels products. This will redirect refinery owners to domestic feedstocks and away from imported feedstock sources. See H.R. 5653, Section 7.

4. Provide Explicit DOE Authority and Appropriations for Loan Guarantees

EPAct 2005 establishes a loan guarantee program within DOE. However, DOE feels that the Federal Credit Reform Act of 1990 prevents it from issuing loan guarantees until it has an authorization in an appropriations bill. We recommend that Congress provide authorization in the form of a federal loan facility to support the first 100,000 bpd of new production capacity for alternative liquid fuel facilities. We also recommend that appropriations be provided for technologies demonstration, as provided in the EPAct 2005. See S. 3325, Section 3;

5. Fund the DoD Alternative Fuels Testing and Development Program

An assured supply of turbine (jet) fuels is critically important to national defense and the commercial aviation industry. The Department of Defense (DoD) currently has an Assured Fuels Initiative underway to evaluate, demonstrate, and qualify turbine (jet) fuels made from alternative energy resources for use in military aircraft, ships and diesel-powered ground vehicles. The program is coordinated with the industry organizations responsible for turbine fuel standards, and will simultaneously qualify these fuels for use in commercial aircraft. The new fuels are expected to improve aircraft engine life and reduce soot output, thus offering important economic and environmental advantages. They will also be freely interchangeable with existing turbine fuels in keeping with the DoD Single Battlefield Fuel policy, and avoiding any complex changeover period between fuel types. The ultimate goal is to develop a Joint Battlefield Use Fuel of the Future (J-BUFF).

By qualifying turbine fuels from alternative resources in military equipment, the Assured Fuels Initiative will prepare the DoD to use an assured domestic fuel supply, and accelerate by several years the acceptance of these fuels by commercial aviation. We encourage Congress to fully fund DoD's fuel testing program through FY 2013. See S. 3325, Section 10.

6. Authorize and Fund Military Purchases of Alternative Fuels Under Long-term Contract

Oil consumption by U.S. military forces totals approximately 300,000 bpd. Through the development of BUFF specifications, a substantial portion of this can be met with domestically produced alternative liquid fuels. DoD desires to enter into long term contracts for the purchase of alternative fuels made from domestic U.S. resources as part of DoD's Total Energy Development (TED) Program. We encourage Congressional support for the TED program, including extending its long-term contracting capabilities from five years to as long as 25 years. See S. 3325, Section 11.

7. Eliminate The $10 Million Cap for Tax Exempt Industrial Development Bonds

To encourage investment, certain pollution control and solid waste disposal facilities are currently not included in the $10 million limit on tax exempt Industrial Development

Bonds (IDBs). We recommend that alternative liquid fuels production facilities be added to this list of activities having no tax exempt IDB size limits.

8. Provide Regulatory Streamlining for the Production of Alternative Liquid Fuels

In order to facilitate the rapid scale-up of alternative liquid fuels production capabilities in the U.S., regulatory changes are necessary. Standardizing, simplifying, and expediting the permitting process for manufacturing/processing facilities, mines, agricultural operations, and necessary infrastructure is crucial, and our recommendations to address this problem include:

- Standardize, simplify, and expedite permitting and siting with joint federal, state and local processes, policies, and initiatives.
- Make appropriate federal sites available for alternative liquid fuels manufacture, including Base Realignment and Closure (BRAC) military sites.
- Exempt initial alternative liquid fuels processing facilities from New Source Review (NSR) and National Ambient Air Quality Standards (NAAQS) offset requirements.
- Prioritize, expand, and promote the reforestation work being done to accelerate the rate of tree growth by creating optimal soil conditions at reclaimed mine sites.

See S. 3325, Section 5

9. Establish a Self-sustaining Insurance Corporation to Provide Market Risk Insurance

We encourage Congress to establish the Strategic Energy Security Corporation (SESC) as a self-funding, self-sustaining government corporation that will administer a new alternative liquid fuels market insurance program to protect against predatory pricing by OPEC and others. SESC will provide the following functions:

- Collect insurance premiums from companies that “opt in” to the SESC insurance program
- Invest net premiums in an insurance fund for future payout to program members if and when necessary
- Facilitate market insurance payments to members if oil prices fall below a defined “Low Trigger Price”
- Administer the collection of “standby” insurance fees, to be levied on imported oil if oil prices fall below the “Low Target Price” and the accumulated investment pool of insurance premiums is exhausted

10. Expand the Strategic Petroleum Reserve (SPR) Program to Include Alternative Liquid Fuels Products

Congress should examine the feasibility of purchasing and storing "finished" alternative fuel products such as diesel fuel, jet fuel, heating oil, and ethanol at locations strategically dispersed throughout the U.S., as an extension of the SPR program.[1] Fischer-Tropsch (FT) wax produced from coal, biomass, and oil shale may be an ideal product for this purpose, and this wax is an alternative to producing diesel and jet fuels. The wax has a very long shelf life, and can be upgraded to superior quality fuels much more quickly and inexpensively than crude oil. Alternative fuels could be purchased by the SPR under long-term contract, and Congress should authorize the sale of portions of the crude oil currently in storage to fund these purchases. See S. 3325, Section 10.

11. Provide Incentives for Existing Ethanol Plants to Convert to Coal

Until recently, the ethanol plant fuel source of choice for process heat and electricity was natural gas. However, with the recent increases in natural gas prices, new ethanol plants are opting for coal firing, and limited domestic natural gas supplies have necessitated increasing imports of this fuel as LNG to produce ethanol. We recommend providing for 100 percent expensing in the year of outlay for the cost of converting ethanol plants currently using natural gas to domestic coal, if the new plant is placed in service by 2010. See H.R. 5653, Section 8.

12. Provide Incentives for Enhanced Oil Recovery and Enhanced Coalbed Methane Recovery Using CO_2 Captured From Alternative Fuel Plants

The capture and use of the CO_2 from alternative liquid fuel plants can greatly expand domestic oil production from existing oil fields and enhance methane recovery from coalbed methane operations. To lower the barriers to expanded use of CO_2 injection we recommend:

- Exclusion of the oil produced from the Alternative Minimum Tax
- Increasing the investment tax credit to 50 percent
- Provision of federal royalty and severance relief until the investment in CO_2 injection is recovered
- Provision of access to federal lands for construction of CO_2 pipelines

See H.R. 5653, Section 5.

State Fiscal, Tax, Legislative, and Regulatory Recommendations

SSEB recommends that the following policies be implemented at the state and local level to encourage the private sector to step forward on a massive scale. The specific fiscal,

[1]There are only four centrally located SPR storage sites in the U.S. -- two in Texas and two in Louisiana. All four sites are centrally situated on the hurricane-prone Gulf Coast, making them vulnerable to natural disaster and also to terrorist attack.

tax, legislative, and regulatory recommendations presented below are designed to jump-start early facilities and complement the federal incentives designed in order to encourage private sector commitments. Each state must assume responsibility for its contribution to the national objective of Energy Security and Independence. A number of states committed to alternative liquid fuel facilities have already taken steps to provide some incentives, but a more consistent approach is needed to avoid unnecessary competition between the states. Any gaps in state incentives requiring legislation should be enacted at the next convening of the state legislature.

1. **Authorize and Fund Multi-year State and Local Government Purchases of Plant Output, Especially Alternative Transportation Fuels, Under Long-term Contract**

   We recommend providing for transportation fuel, electricity and steam purchasing under multi-year contracts of at least 10 years, arranging for state and local contractors to purchase transportation fuel and other products, and securing transportation fuels under multi-year contracts for first responders for use in case of emergency.

2. **Provide State Loans or Grants on Matching Basis with Private Industry to Assist with Preliminary Engineering and Site Qualification.**

3. **Provide for Tax Incentives**

   A number of states have tax incentives on the books. Provision should be made for explicit investment tax credits, corporate tax abatement, and local property tax abatement.

4. **Provide for Fiscal Incentives**

   We recommend that states provide loans at favorable rates, and qualification for industrial development bonds.

5. **Incentivize the use of CO_2 for carbon capture and storage**

   A few states have developed a variety of incentives for what is known as “tertiary recovery”. We recommend that all states provide for state royalty and severance tax relief until the investment in CO_2 injection is recovered

   a. Also, providing access to state lands for construction and expansion of CO_2 pipelines will stimulate the growth of the needed infrastructure.

6. **Provide Regulatory Streamlining and Central State Agency Coordination of the Permitting Process for the Production of Alternative Liquid Fuels**

   Some states have developed an enlightened approach to siting new facilities. We recommend pre-qualification of sites,

   a. identification of options to meet air and water requirements,

b. standardization and expedited permitting and siting under established timelines with joint federal, state and local processes, policies, and initiatives,
   making appropriate state and local government sites, including suitable brownfield sites, available for alternative transportation fuels manufacture, and
c. encouraging local authorities to modify approaches to zoning and other land use and business regulations to accommodate alternative transportation fuels production facilities.

7. Involve State Research and Development Enterprises

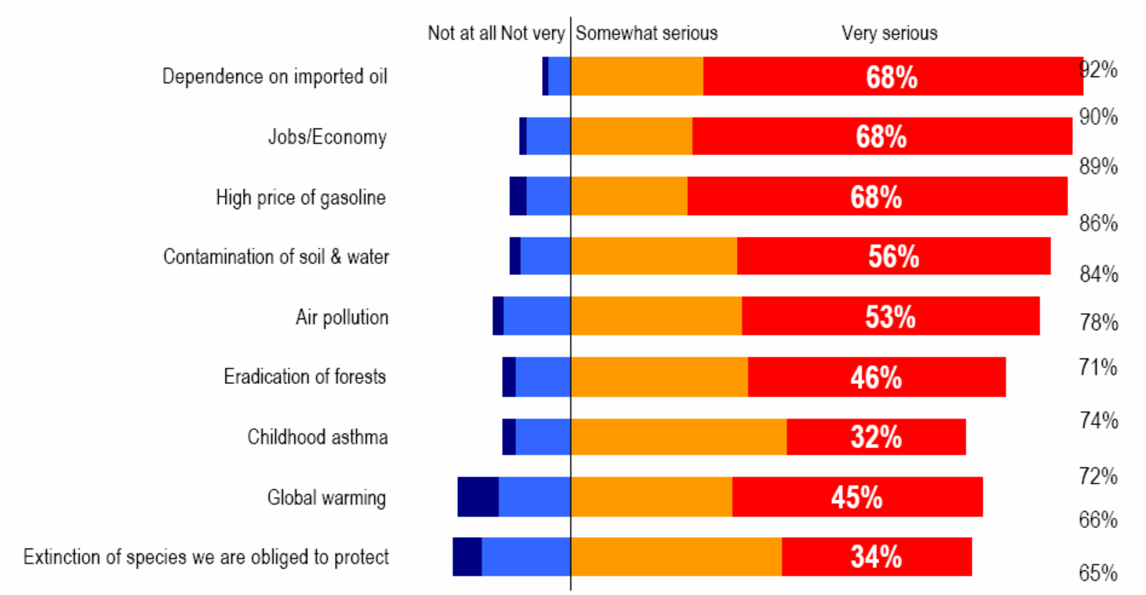
Many states have important capability to provide R&D support to supplement the Federal activity. We recommend that states engage in a collaborative arrangement to make best use of the available R&D funding aligned with the needs of the commercial development interests.

A TOP CONCERN OF AMERICANS

The following summarizes the key findings of a national survey conducted by the Yale Center for Environmental Law and Policy in May 2005. Note that the price of oil and gasoline have both risen since the date of the survey.

Top Concerns: Dependence on Imported Oil

Americans are nearly unanimous in the belief that dependence on imported oil is a very serious problem. Fully 92% say it is a serious problem and 68% say it is a 'very' serious problem.



Yale Environment Survey, May 15-22 2005, 1002 interviews

Americans are more concerned about our dependence on imported oil than about global warming, air pollution or contamination of soil and water. Democrats (70%), Republicans (68%) and Independents (66%) all agree, this is a very serious problem.

TAKE ACTION

You can help to advance the cause of American liquid transportation fuels independence. First and foremost, please support the legislation we are recommending. This is vital.

We are currently seeking additional contributions to help us carry on with the next phase of the American Energy Security program: educating policy makers, stakeholders, the media and the American people about the possibilities. Our goal is to raise at least $500,000 pursuant to this mission.

Those interested in helping to fund our ongoing outreach program should call Ken Nemeth, executive director of the Southern States Energy Board, at 770-242-7712 or Jim Mayer, president of A. J. Mayer International, at 717-359-0014.

We also invite you to visit our website to learn more about our program and how you can help. When you visit, please subscribe to our email list so that we can keep you current regarding our activities. And please be sure to invite your friends, colleagues and associates to visit the site. Thank you.

www.AmericanEnergySecurity.org

I. INTRODUCTION

I.A. The Critical Role of Oil in the U.S. Economy

Oil is the lifeblood of the U.S. economy and is crucial for the U.S. and all modern societies.[1] It fuels the vast majority of transportation equipment – automobiles, trucks, airplanes, trains, ships, farm equipment, etc, and is the primary feedstock for many of the chemicals that are essential to modern life. Global oil supply and demand dynamics will continue to shape history in the 21st century – just as they did through much of the 20th century. Conventional global oil production may be nearing its peak, as many experts are predicting, and the days of cheap oil appear to be over. After nearly two decades of reasonably stable, affordable levels, oil prices have recently increased dramatically, and over the last four years crude oil prices have nearly tripled as global demand increased and supplies tightened -- see Table I-1.

Table I-1
Brent Crude Oil Spot Prices*

	2002	2003	2004	2005	2006
Price/bbl*	$24.69	$27.14	$35.58	$56.92	$71.12
Percent change		9.9%	31.1%	60%	25%

*Brent spot price on June 17th of each year, except for 2006 prices quote as of 5-26-06. Data in current year (nominal) dollars.

All energy prices have increased over the past decade, but whereas petroleum-based product prices have tripled, electricity and coal prices have increased only about two percent annually. Table I-2 lists the price levels of selected energy commodities and their increases over the last two five-year periods.[2] From 1995 to 2000, coal and electricity prices fell while gas and petroleum based products rose from 40 to almost 70 percent. However, the most recent period, 2000-2005 shows even higher increases. U.S. electricity prices rose 19 percent and coal prices rose 28 percent, but natural gas, motor gasoline, and #2 distillate prices increased at least twice as much as coal prices, rising from almost 60 percent to nearly 90 percent.

---

[1]See World Energy Council, *Drivers of the Energy Scene*, December 2003, for a detailed examination of the relationship of GDP and energy across the world economies.

[2]See U.S. Department of Energy, Energy Information Administration (EIA): *Electric Power Annual, 2004*, November 2005, and *State Average Price* series on all end-users by all suppliers, May 2006; *Natural Gas Navigator, Natural Gas Prices, City Gate Price,* May 2006; *Monthly Energy Review*, for *Cost of Fossil-Fuel Receipts at Electric Generating Plants* (including taxes), April, 2006, *Average Price of Coal Delivered to End Use Sector by Census Division and State*, *Electric Utility Plants*, May 2006, *Annual Coal Report*, 2001; *Petroleum Navigator, Gasoline Prices by Formulation, Grade, Sales Type (Sales to End-Users - Average)* and *No. 2 Distillate Prices by Sales Type (Sales to End users, Average)*, May 2006.

Table I-2
Selected Energy Prices in the U.S., 2000-2005

	Electricity	Natural Gas	Coal	Motor Gasoline	#2 Distillate
	cents/kwh	*dollars/tcf*	*dollars/mbtu*	*dollars/gallon*	*dollars/gallon*
1995	6.89	2.78	1.32	0.76	0.56
1996	6.86	3.27	1.29	0.84	0.68
1997	6.85	3.66	1.27	0.83	0.64
1998	6.74	3.07	1.25	0.66	0.49
1999	6.64	3.10	1.22	0.76	0.58
2000	6.81	4.62	1.20	1.09	0.93
2001	7.31	5.72	1.23	1.02	0.84
2002	7.22	4.12	1.25	0.94	0.76
2003	7.42	5.85	1.28	1.14	0.94
2004	7.62	6.65	1.36	1.42	1.24
2005	8.09	8.64	1.54	1.73	1.74
Change in Price					
'95-'00	-1%	66%	-9%	43%	67%
'00-'05	19%	87%	28%	59%	86%

Source: U.S. Energy Information Administration and Management Information Services, Inc., 2006. Data in current year (nominal) dollars.

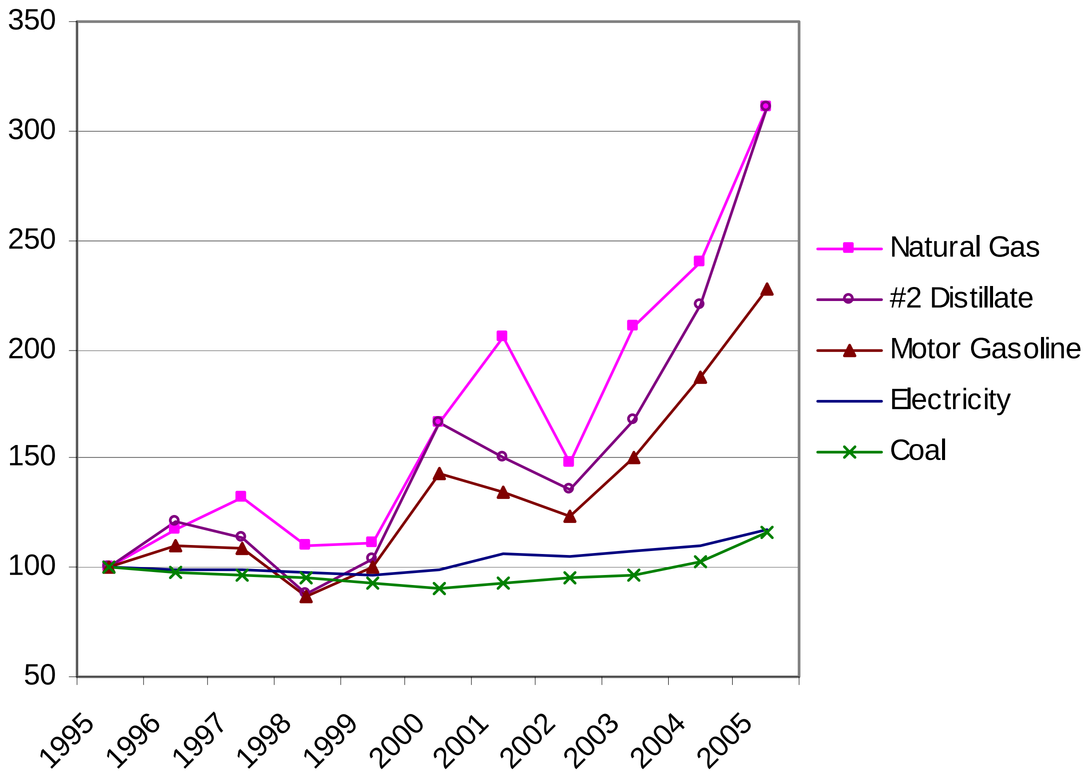
Figure I-1 shows U.S. energy price levels over the last ten years indexed to 1995 levels. Coal prices have shown the greatest stability over the period, rising only 17 percent. Because of the large amount of coal used for electricity generation, electricity prices have also remained remarkably stable over the ten-year period. However, energy commodities that are petroleum- and gas-based became increasingly expensive including natural gas, motor gasoline, and No. 2 distillate/diesel fuel.

The latest oil price surge is unique. Unlike the high prices that resulted from the 1973 oil embargo and the Iranian revolution of 1979, there have been no recent major oil supply disruptions. Either oil producers around the world simply cannot meet rapidly increasing global demand, or OPEC members (and possibly others) are manipulating oil supplies and prices for maximum profit (and perhaps to retaliate economically against U.S. policies on terrorism and democracy). In either case, rapidly rising oil prices have disturbing implications for the U.S. economy and for U.S. energy security.

Oil and natural gas price increases in recent years have had a profound impact on U.S. businesses. Increased energy prices have required companies to pass along price increases to consumers, change capital investment, alter the way businesses are run, or, in the extreme, go out of business. The sectors most at risk include:

- The aviation industry, both commercial airlines and cargo airlines, including air transportation industry manufacturers and suppliers

Figure I-1
Indices of Selected Energy Price Levels in the U.S., 2000-2005
(1995=100)



Source: U.S. Energy Information Administration and Management Information Services, Inc., 2006.

- The agriculture industry, including pesticide and fertilizer manufacturers
- The automobile industry, including the supporting parts manufacturers and the sales infrastructure
- Trucking companies, landscapers, laundry and dry-cleaning firms, restaurants, delivery businesses, taxi and limousine services, florists, and numerous other energy-dependent businesses

Examples of companies already experiencing debilitating energy cost increases are numerous; including:

- American Airlines, which uses more oil annually than the country of Ireland and where 28 percent of the factor input costs are for energy, experiences a $33 million increase in cost *for every penny a gallon* *increase in the price of jet fuel*, and paid *$2.8 billion more for fuel costs in 2005 than in 2003*.[1]

- Dow Chemicals is now paying *$20 billion* for petrochemical feedstocks that cost the company $8 billion just three years ago.[2]

There is convincing evidence that increased energy prices lead to decreased GDP and affect the ability of economies to reach full potential growth; for example:

- According to the International Monetary Fund (IMF), a $5/bbl. increase in the price of oil reduces GDP by one percent.[3]
- According to Alan Greenspan, "The recent rise in oil prices has been substantial enough and persistent enough to influence business decisions, and carried the potential to significantly affect the long-term path of the U.S. economy."[4]

In April 2006, the Federal Reserve Board determined that the increase in energy prices over the past three years has significantly reduced the purchasing power of households and decreased the profits of non-energy firms, thereby restraining both consumer spending and business investment.[5] The Fed estimates that these increases in energy prices have reduced real GDP growth nearly one percent per year over this period. Further, even as the U.S. economy adjusts to higher energy prices, the level of productivity is likely to remain lower than it otherwise would have been, as firms use less energy per worker. The Fed also found that the rise in energy costs has had a significant impact on overall inflation and has also affected core inflation (which excludes the direct effect of energy price increases).

I.B. Peaking of World Conventional Oil Production

The earth's endowment of oil is finite and demand for oil continues to increase, and at some future date conventional oil supply will no longer be capable of satisfying world demand. At that point world conventional oil production will have peaked and begin to decline. It is important to recognize that oil production peaking is not "running out." Peaking is an oil field's maximum oil production rate, which typically occurs after roughly half of the recoverable oil in the field has been produced. What is likely to happen on a world scale is similar to what happens to individual oil fields, because world production is the sum total of production from thousands of oil fields.

The peaking of world oil production presents the world with an unprecedented problem. As peaking is approached, liquid fuel prices and price volatility will increase

[1]See "As Oil Prices Go Up, Companies Struggle to Contain Their Costs," Steven Mufson, *Washington Post*, May 11, 2006.
[2]Ibid.
[3]See International Monetary Fund, *The Impact of Higher Oil Prices on the Global Economy*, December 2000.
[4]Alan Greenspan speech, April 28, 2004.
[5]"Letter from Federal Reserve Board Chairman Ben Bernanke to Representative J. Gresham Barrett," April 5, 2006.

dramatically, and, without timely mitigation, the economic, social, and political costs will be unprecedented. Indeed, the rapid rise in world oil prices in the 2004-2006 period may likely appear modest in comparison to the price escalations and oil shortages that are almost certain to accompany the peaking of world conventional oil production.

Oil was formed by geological processes millions of years ago and is typically found in underground reservoirs of dramatically different sizes, at varying depths, and with widely varying characteristics. The largest oil reservoirs are called “Super Giants,” many of which were discovered in the Middle East. Because of their size and other characteristics, Super Giant reservoirs are generally the easiest to find, the most economic to develop, and the longest lived. The last Super Giant oil reservoirs were discovered in 1967 and 1968, and since then only smaller reservoirs of varying sizes have been discovered.

The inevitability of world oil production peaking followed by declining production follows from the well-established fact that the output of individual oil fields rises after discovery, reaches a peak, and declines thereafter. Once oil has been discovered via an exploratory well, full-scale production requires many more wells across the reservoir to provide multiple paths that facilitate the flow of oil to the surface. This multitude of wells also helps to define the total recoverable oil in a reservoir – its so-called “reserves.”[1]

World oil demand is expected to grow 50 percent by 2030,[2] and to meet that demand, ever-larger volumes of oil will have to be produced. Since oil production from individual oil fields grows to a peak and then declines, new oil fields must be continually discovered and brought into production to compensate for the depletion of older ones. If large quantities of new oil are not discovered and brought into production somewhere in the world, then world oil production will no longer satisfy demand. That point is called the peaking of world conventional oil production. When world oil production peaks, there will still be large reserves remaining. Peaking means that the rate of world oil production cannot increase; it also means that production will thereafter decrease with time.

Extensive exploration has occurred worldwide for the last 30 years, but results have been disappointing. If recent trends hold, there is little reason to expect that exploration success will dramatically improve in the future. This situation is evident in Figure I-2, which shows the difference between annual world oil reserves additions minus annual consumption.[3] The image is one of a world moving from a long period in which reserve

---

[1]The concept of reserves is generally not well understood. “Reserves” is an estimate of the amount of oil in an oil field that can be extracted at an assumed cost. Thus, a higher oil price outlook often means that more oil can be produced, but geology places an upper limit on price-dependent reserves growth; in well managed oil fields, it is often 10-20 percent more than what is available at lower prices. Reserves and production should not be confused. An oil field can have large estimated reserves, but if the field is past its maximum production, the remaining reserves can only be produced at a declining rate. Satisfying increasing oil demand not only requires continuing to produce older oil fields with their declining production, it also requires finding new ones capable of producing sufficient quantities of oil to both compensate for shrinking production from older fields and to provide increases demanded by the market.

[2]International Energy Agency, *World Energy Outlook, 2005*.

[3]K. Aleklett and C.J. Campbell, *"The Peak and Decline of World Oil and Gas Production"*. Uppsala University, Sweden, ASPO web site, 2003; Roger H. Bezdek, “Peaking of World Oil Production: Impacts and the Scope of the Mitigation Problem,” presented at the Southern California Energy Conference “Our Energy Future,” Los

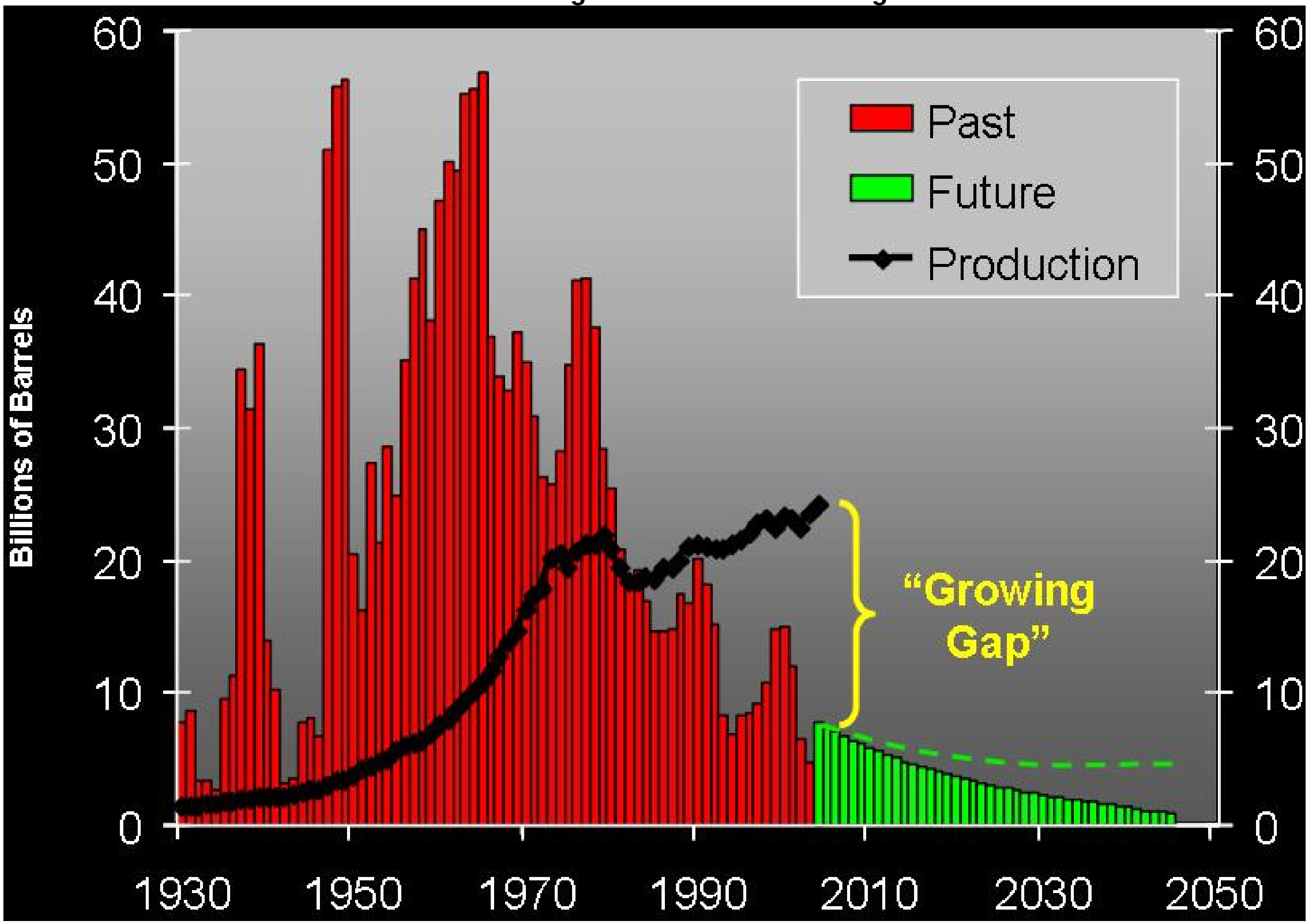
additions were much greater than consumption, to an era in which annual additions are falling increasingly short of annual consumption. Recently, many credible analysts have become much more pessimistic about the possibility of finding the huge new reserves needed to meet growing world demand. Even many of the optimistic forecasts suggest that world oil peaking will occur in less than 20 years. Various individuals and groups have used available information and geological estimates to develop projections for when world oil production might peak, and a sampling of recent projections is shown in Table I-3.

Table I-3. Projections of the Peaking of World Oil Production

Projected Date	*Source of Projection*	*Background & Reference*
2006-2007	Bakhitari, A.M.S.	Oil Executive (Iran)[1]
2007-2009	Simmons, M.R.	Investment banker (U.S.) [2]
After 2007	Skrebowski, C.	Petroleum journal editor (U.K.)[3]
Before 2009	Deffeyes, K.S.	Oil company geologist (ret., U.S.)[4]
Before 2010	Goodstein, D.	Vice Provost, Cal Tech (U.S.)[5]
Around 2010	Campbell, C.J.	Oil company geologist (ret., Ireland)[6]
After 2010	World Energy Council	World Non-Government Org.[7]
2012	Pang Xiongqi	Petroleum Engineer (China)[8]
2010-2020	Laherrere, J.	Oil geologist (ret., France)[9]
2016	EIA nominal case	DOE analysis/ information (U.S.)[10]
After 2020	CERA	Energy consultants (U.S.)[11]
2025 or later	Shell	Major oil company (U.K.)[12]

Angeles, March 2006.
[1]Bakhtiari, A.M.S. "World Oil Production Capacity Model Suggests Output Peak by 2006-07." *Oil and Gas Journal*. April 26, 2004.
[2]Simmons, M.R. ASPO Workshop. May 26, 2003.
[3]Skrebowski, C. "Oil Field Mega Projects - 2004." *Petroleum Review*. January 2004.
[4]Deffeyes, K.S. *Hubbert's Peak-The Impending World Oil Shortage*. Princeton University Press. 2003.
[5]Goodstein, D. *Out of Gas – The End of the Age of Oil*. W.W. Norton. 2004
[6]Campbell, C.J. "Industry Urged to Watch for Regular Oil Production Peaks, Depletion Signals." *Oil and Gas Journal*.. July 14, 2003.
[7]*Drivers of the Energy Scene*. World Energy Council. 2003.
[8]Pang Xiongqi. The Challenges Brought by Shortages of Oil and Gas in China and Their Countermeasures. ASPO Lisbon Conference. May19-20, 2005.
[9]Laherrere, J. Seminar Center of Energy Conversion. Zurich. May 7, 2003
[10]DOE EIA. "Long Term World Oil Supply." April 18, 2000. See Appendix I for discussion.
[11]Jackson, P. et al. "Triple Witching Hour for Oil Arrives Early in 2004 – But, As Yet, No Real Witches." C*ERA Alert*. April 7, 2004.
[12]Davis, G. "Meeting Future Energy Needs*." The Bridge.* National Academies Press. Summer 2003.

Figure I-2
The World is Consuming More Oil Than is Being Discovered



I.C. U.S. Oil Dependence

In his 2006 State of the Union message, President Bush stated that the U.S. was "addicted to oil" and that the nation must reduce its dependence on oil imports. This will be very difficult, since:

- The U.S. consumes 21 million barrels of petroleum products per day, 58 percent of which is imported.
- Oil accounts for 95 percent of the energy used in the U.S. transportation sector, and the nation relies on a transportation system that evolved based on cheap oil and that remains dependent on readily available gasoline, diesel, and jet fuel.
- Over 7.7 million households, primarily in the northeastern United States, heat their homes with distillate fuel oil.
- Refined petroleum products are the basic feedstocks required in the production of many manufactured products, such as plastics.
- Oil refining produces asphalt and road oil and virtually all lubricants used in transportation and industry.
- The U.S. agricultural system is highly dependent on oil to seed, grow, manufacture, preserve, and ship food products to consumers, and fertilizers, pesticides, herbicides, irrigation, and farm equipment all depend on oil.[1]
- National security depends on the timely movement of military personnel and equipment, and DOD oil use totals 300,000 barrels per day (bpd).

Petroleum accounts for about 40 percent of U.S. energy consumption, and that percentage has grown consistently over the past two decades due to steady increases in fuel consumption. EIA projects this 40 percent figure will persist in American society through 2030 as the nation maintains its dependence on oil.[2] Transportation accounts for more than two-thirds of U.S. oil consumption, and this portion is increasing. Further, 95 percent of U.S. transportation is dependent on liquid fuels, and this dependence will persist for decades to come.[3]

I.D. The U.S. Oil Security and Independence Imperative

The U.S. faces the prospect of extended oil supply shortages, rising prices, growing trade deficits, and economic and national security vulnerability unless industry and government act decisively to develop unconventional U.S. liquid fuel supplies. There are four factors that highlight our vulnerability, and may very well define our future:

---

[1]In addition, it is estimated that the average food product is transported about 1,500 miles before it is consumed.

[2]U.S. Energy Information Administration, *Annual Energy Outlook, 2006*, February 2006.

[3]EIA projects that world unconventional production (including oil sands, bitumen, biofuels, coal-to-liquids, and gas-to-liquids) will increase by 9.7 million barrels between 2003 and 2030, representing 25 percent of the total world liquid fuel supply increase. See U.S. Energy Information Administration, *International Energy Outlook*, June 2006.

- America is dangerously dependent on the OPEC cartel and other oil suppliers that have instituted record prices over the past several years, manipulating markets to maximize their profits, at great cost to the U.S.
- As noted, a growing number of experts, including some major oil companies, believe that within the next decade world conventional oil production will peak and begin a steady decline. Some contend that we have already reached the peak.
- The U.S. faces unprecedented global competition for oil from China, India, and other nations. This competition grows more intense every quarter as supplies tighten and oil importing countries strive to secure oil supplies.
- The current U.S. liquid fuels infrastructure is vulnerable to natural disasters and to terrorism.

To insure against these risks, and to provide for price stability and future economic prosperity and national security, America must reduce its growing dependence on foreign oil suppliers by producing its own liquid fuels. The opportunities created by a transition toward energy security and independence will be immense.

This study focuses on the rapid development of an alternative oil and liquid fuels production base in America utilizing our vast domestic resources of coal, oil shale, and biomass. It also recognizes the need for increased U.S. transportation fuel efficiency, sensible conservation, and improved domestic oil recovery programs emphasizing $C0_2$-enhanced oil recovery and sequestration.

America's future may hinge on the choices we make regarding liquid fuels. There are key factors that dictate that we must take action to counter these threats or risk high, volatile oil prices and supply shortfalls over long periods resulting in dire economic consequences. Will we continue to tolerate the instability, high economic costs, and national security risks of growing reliance on imported oil? Or will we choose to establish an aggressive path toward energy security and independence by developing a solid base of alternative liquid fuels production from our own vast resources – as outlined in this study?

I.E. Plan of the Study

The U.S. is the Middle East of non-conventional liquid fuels resources, with oil equivalent reserves rivaling those of world conventional oil resources. Trillions of tons of U.S. oil shale, coal, and renewable biomass are available to be profitably converted to premium quality liquid fuels using existing commercial and near-commercial technologies, and record fuel prices clearly reflect the need for alternative domestic liquid fuels production. This study estimates the substantial economic and national security benefits that can be created by implementing government policies that encourage the rapid development of unconventional domestic fuels production and move the U.S. toward energy security and independence (ESI). Specifically:

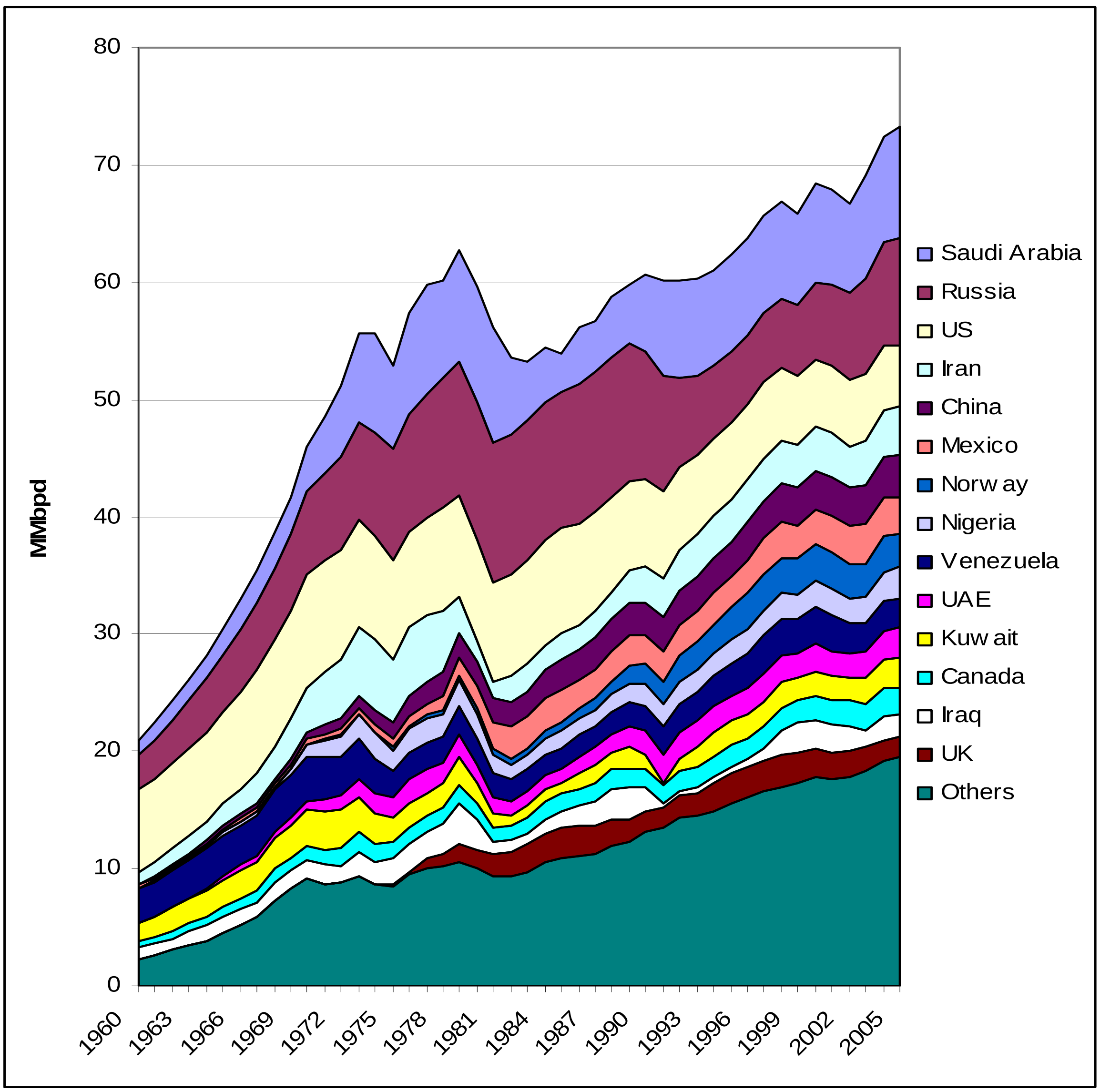
- Chapter II analyzes world oil markets, focusing on supply and demand, growing international competition for oil, crude oil and liquid fuels prices, peak oil risks, and U.S. import risks.
- Chapter III assesses the major U.S. energy resources, highlighting the estimated volume, character, and geographic location of each resource category and the potential of each to support large-scale alternative oil and liquid fuels production through the 21st century. The resources assessed include coal, oil shale, biomass, enhanced oil recovery, and transportation efficiency and conservation.
- Chapter IV provides a technology assessment of U.S. energy resources, and includes a brief description of the commercial and near-commercial technologies available to produce and to save large volumes of liquid fuels. It also presents production capabilities and capital and operating cost profiles for prototype liquid fuels production facilities.
- Chapter V analyzes the economics of U.S. energy security and independence, and discusses the implications of U.S. energy dependence and insecurity, the rationale for energy independence, the role of energy policy, and the costs of energy dependence.
- Chapter VI assesses the economic and jobs benefits of energy security and independence, and estimates the benefits to the economy of pursuing transportation fuel efficiency and liquid fuels initiatives that will permit the U.S. to achieve liquid fuel independence by 2030. It summarizes a year-by-year plan for the rapid scale up of oil and liquid fuels production in each of the resource categories, including annual production estimates, capital and operating cost estimates, projected profits, tax revenues, etc.
- Chapter VII addresses the net positive benefits of the energy security and independence plan presented in this study. It discusses the environmental impacts and benefits of mining and polygen plant construction and operations, and presents mine impact mitigation strategies such as reforestation, with discussion how responsible environmental stewardship can be continued while rapidly expanding domestic coal and oil shale mining.
- Chapter VIII presents policy recommendations for federal, state, and local governments to facilitate development of liquid fuel initiatives that result in U.S. energy security and independence.

II. OIL MARKETS: ANALYSIS AND FORECAST

II.A. International Production, Consumption, Prices, and Reserves

The United States, while a major oil producer and the world's largest consumer of petroleum, has increasingly been subject to the "World Oil Market." In 1960, the U.S. production of oil was 7.0 million barrels of oil per day (MMbpd), supplying a full one-third of the world's demand of 21.0 MMbpd -- as shown in Figure II-1.

Figure II-1.
World Oil Production, 1960-2005



Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2004*; *International Petroleum Monthly*, April 2006; and MISI, 2006.

However, over the past half century the level and geographic distribution of oil production has expanded and now includes 123 countries with consistent, measurable production, and few countries currently have absolute control over oil production levels and prices. As seen in Table II-1, Saudi Arabia was the largest producer in 2005, producing 9.6 MM bpd, but it accounted for only 13 percent of world oil production. Russia was the second-largest producer and produced 9.1 MM bpd, accounting for just over 12 percent. While the U.S. is the world's third largest producer of oil, its output represents only seven percent of the world's total production of 73.3 MMbpd of crude oil.[1]

Table II-1.
The Top Oil Producing Countries, 2005

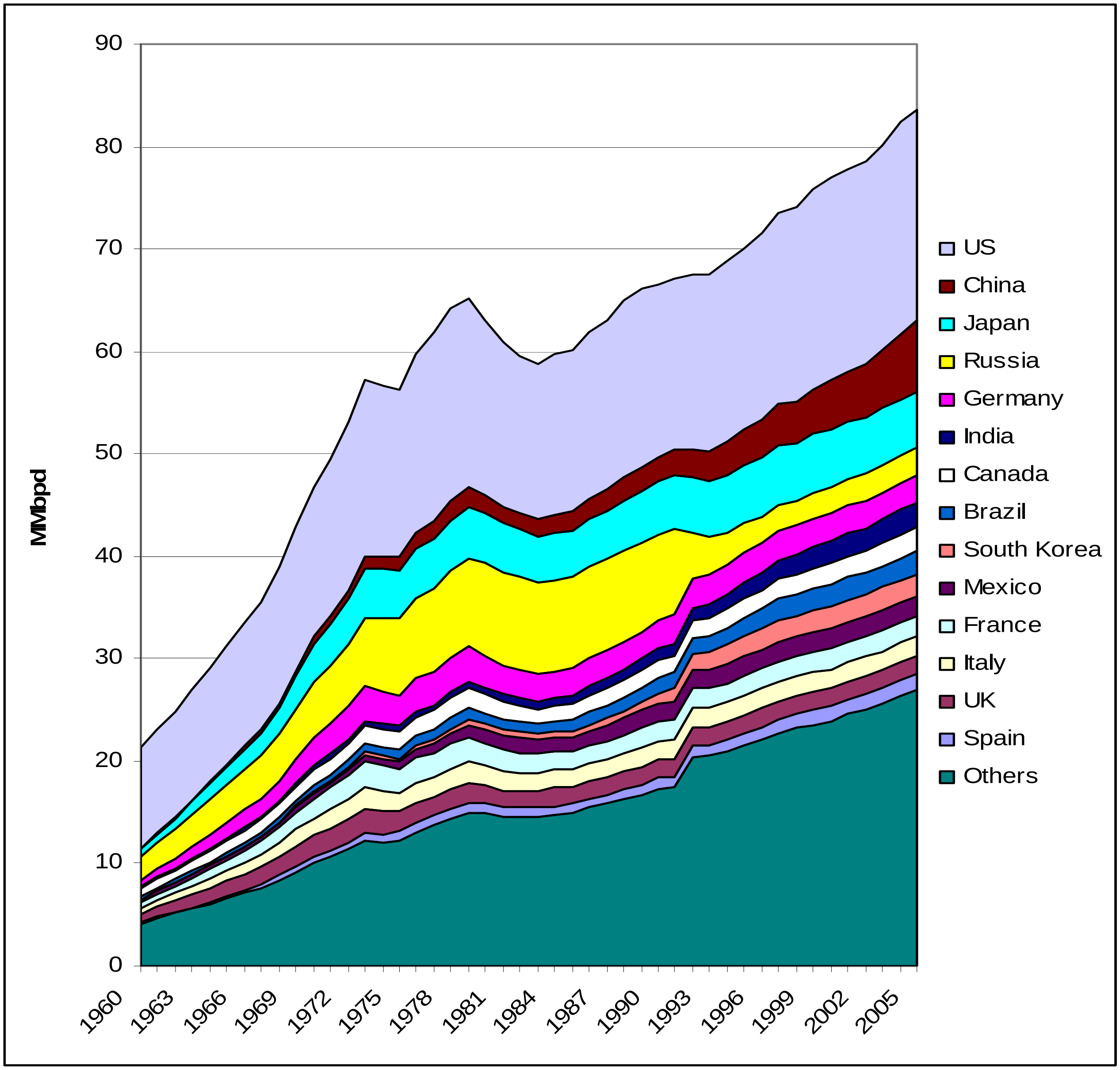
Rank	Country	MM bpd	Percent
1	Saudi Arabia	9.6	13.0
2	Russia	9.1	12.4
3	United States	5.1	7.0
4	Iran	4.1	5.6
5	China	3.6	4.9
6	Mexico	3.3	4.5
7	Norway	2.7	3.7
8	Nigeria	2.6	3.6
9	Venezuela	2.6	3.5
10	United Arab Emirates	2.5	3.5
11	Kuwait	2.5	3.4
12	Canada	2.4	3.2
13	Iraq	1.9	2.6
14	United Kingdom	1.7	2.3
	109 other countries	*19.5*	*26.6*
	Total	**73.3**	**-**

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2004*; *International Petroleum Monthly*, April 2006; and MISI, 2006.

The U.S. has been the world's largest consumer of oil over the last 45 years. In 1960, the U.S. consumed about half of the total oil consumed, almost 10 MMbpd -- as shown in Figure II-2. Russia/Soviet Union was the far-distant second largest consumer, accounting for 11 percent of total world consumption. Remarkably, in 1960 no other country consumed more than 1 MM bpd.

[1]The difference between the 2005 world oil production figure of 73 MM bpd and world consumption figure of 84 MM bpd is due primarily to refinery gain.

Figure II-2.
World Oil Consumers, 1960-2005



Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2004*; *International Petroleum Monthly*, April 2006; and MISI, 2006.

The present situation is much different, and dozens of countries currently consume over 1 MMbpd. U.S. consumption has risen to almost 21 MMbpd, but accounts for around 25 percent of the world's total consumption, as shown in Table II-2. Oil consumption in China expanded very rapidly over the past two decades, and in 2005 it was the world's second largest oil consumer, consuming 7.0 MMbpd. Japan, Russia, Germany, and India all now consume more than 2.5 MMbpd, and demand in India is also growing rapidly. In

2005, the top ten oil consuming nations accounted for 60 percent of total world consumption, while 204 other countries accounted for the remaining 40 percent of total world consumption.

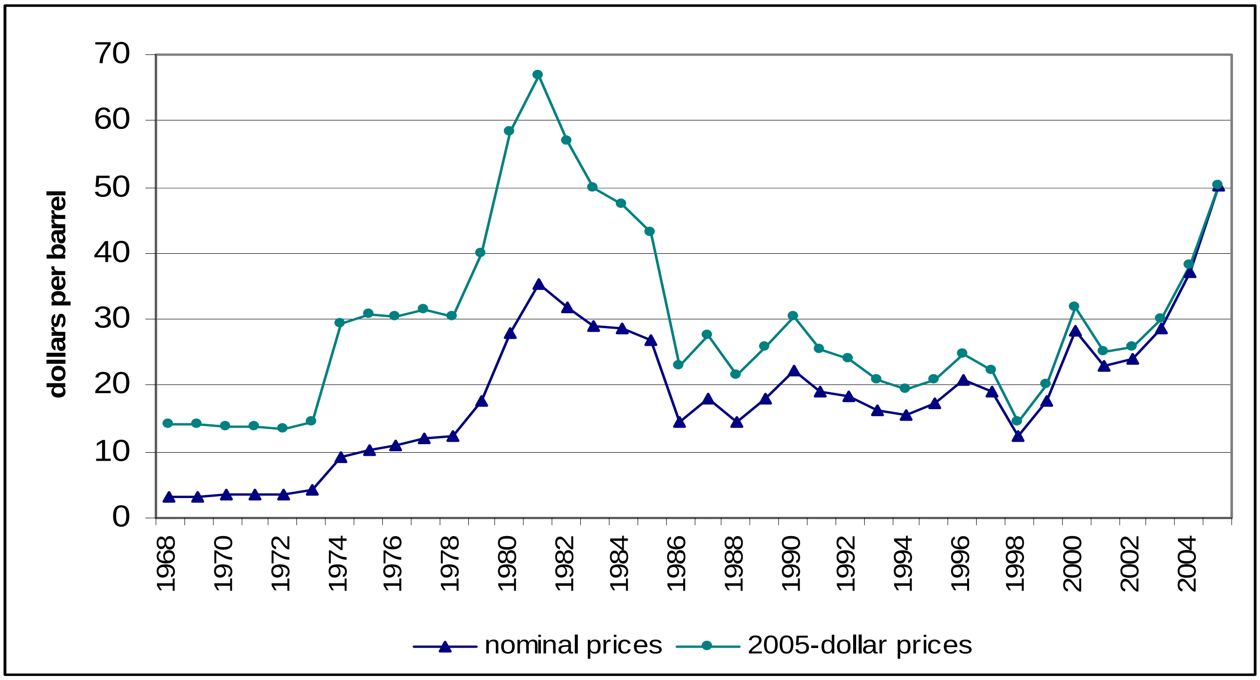
Table II-2.
The Top Oil Consuming Countries, 2005

Rank	Country	MM bpd	Percent
1	United States	20.7	24.7
2	China	7.0	8.3
3	Japan	5.4	6.5
4	Russia	2.7	3.3
5	Germany	2.6	3.1
6	India	2.5	2.9
7	Canada	2.3	2.7
8	Brazil	2.2	2.7
9	South Korea	2.2	2.6
10	Mexico	2.1	2.5
11	France	2.0	2.4
12	Italy	1.8	2.2
13	United Kingdom	1.8	2.2
14	Spain	1.6	1.9
	200 other countries	*26.9*	*32.1*
	Total	***83.6***	**-**

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2004*; *International Petroleum Monthly*, April 2006; and MISI, 2006.

Over the last 40 years, oil prices have been primarily and subtly affected by patterns of economic growth and the consequent continually increasing requirements for oil. However, most of the largest price changes during the period can be attributed more to political dynamics. Figure II-3 shows the historical prices to U.S. refiners of crude oil from 1968 through 2005. Rapid price increases in 1973-74, 1980-81, 1989-90, and 1999-2000 can be attributed to oil embargoes, supply disruptions, armed conflicts, and related events. Large, consistent price increases over the last four years have been driven primarily by rapidly increasing demand, especially in China and India, and have led to refiner acquisition prices for oil increasing to $50 in 2005. Evaluating historical prices in constant 2004 dollars indicates that oil prices were actually higher in real terms in 1980, 1981, and 1982. Based on refiner acquisition costs in real dollars, the average annual price of oil peaked in 1981 at almost $67.

Figure II-3.
U.S. Crude Oil Costs to Refiners, 1968-2005



Source: U.S. Department of Energy, Energy Information Administration, "U.S. Crude Oil Composite Acquisition Cost by Refiners," *Petroleum Navigator*, March 13, 2006: and U.S. Department of Commerce, Bureau of Economic Analysis, "GDP and Other Major NIPA Aggregates," *Survey of Current Business*, May 2006; and MISI, 2006.

Looking forward, the price of oil will be determined by the level of production and the level of demand. At some point, the world oil production will peak and this will have profound impacts on the U.S. economy and every country in the world.[1] When conventional oil peaking occurs will be primarily influenced by the amount of conventional oil remaining to be recovered. As noted in Chapter I, there has recently been much discussion and debate concerning the amount of conventional oil reserves available to be developed over the coming decades. Table II-3 lists the proved reserves of conventional oil by country as of 2006, and the data reflect the median of three respected reserves estimates produced and published in the *BP Statistical Review*, the *Oil and Gas Journal*, and *World Oil*. This table indicates that the median estimate is that the world has just under 1.2 trillion barrels of proven conventional oil reserves. The top ten countries with more proved reserves than the U.S. each have unique political relationships with the U.S. as well as other high oil-consuming countries like China and Japan and the western European countries. Whether

[1]See Robert Hirsch, Roger Bezdek, and Robert Wendling, *Peaking of World Oil Production: Impacts, Mitigation, and Risk Management*, report prepared for the U.S. Department of Energy, National Energy Technology Laboratory, February 2005.

oil continues to be traded on a transparent, international market-clearing basis or is increasingly influenced by political and strategic priorities remains to be seen.[1]

Table II-3.
World Conventional Oil Reserves Estimates by Country, 2005

Rank	**Country**	**Oil (billion barrels)**	**Percent**
1	Saudi Arabia	262.7	22.1
2	Iran	132.5	11.1
3	Iraq	115.0	9.7
4	Kuwait	99.7	8.4
5	United Arab Emirates	97.8	8.2
6	Venezuela	77.2	6.5
7	Russia	67.1	5.6
8	Libya	39.1	3.3
9	Nigeria	35.9	3.0
10	Kazakhstan	24.3	2.0
11	United States	21.4	1.8
12	China	17.1	1.4
13	Canada	16.8	1.4
14	Qatar	15.2	1.3
15	Mexico	14.8	1.2
16	Algeria	11.8	1.0
17	Brazil	11.2	0.9
	106 other countries	*128.9*	*10.8*
	Total	**1,188.5**	**-**

Source: U.S. Department of Energy, Energy Information Administration, *World Proved Reserves of Oil and Natural Gas - Most Recent Estimates*, table posted January 18, 2006.

II.B. Forecasts of International Oil Production, Consumption, and Prices

Forecasting oil production and consumption levels and transfer prices is a difficult job, at best, and most historical forecasts have been highly inaccurate.[2] Our research here is based on the forecasts developed by the U.S. Department of Energy's Energy Information Administration (EIA). The forecasts are released annually, are public, and represent the

[1] See the discussion in Robert Hirsch, "Political Based Oil Peaking – An Alternate Scenario," SAIC, September 2005.
[2] See Roger Bezdek and Robert Wendling, "A Half Century of Long-Range Energy Forecasts: Errors Made, Lessons Learned, and Implications For Forecasting," *Journal of Fusion Energy*, Vol. 21. No. 3/4 (December 2003), pp. 155-172.

primary information that U.S. policy-makers use in their law-making process.[1] The latest EIA forecast was released in February 2006, and Table II-4 lists the levels of oil production, both conventional and unconventional, that the agency projects from 2004 through 2030 for selected countries and geographic/political regions. Table II-5 lists selected countries and geographic/political regions and their EIA-projected levels of oil consumption out to 2030.

Table II-4.
Forecast of World Oil Production to 2030

	2004	2010	2015	2020	2025	2030	Annual Growth 2004-2030
	(million barrels per day)						
Conventional	**80.5**	**86.1**	**90.0**	**95.7**	**100.9**	**106.3**	**1.1%**
Middle East	21.3	24.8	25.6	27.0	28.9	31.1	1.5%
Russia	9.3	9.5	9.9	10.7	11.1	11.3	0.7%
United States	8.4	9.4	9.6	9.5	9.1	8.9	0.2%
Africa	3.5	3.6	4.5	5.4	6.7	8.0	3.2%
Caspian Area	2.3	3.0	4.2	5.2	5.3	7.4	4.6%
Other South and Central America	4.2	4.3	5.0	5.8	6.5	7.0	2.0%
Mexico	4.1	4.0	4.2	4.5	4.8	5.0	0.8%
Western Europe	6.9	5.9	5.3	5.2	4.8	4.4	-1.7%
South America	2.8	3.4	3.6	3.7	3.9	4.1	1.5%
Venezuela	2.8	3.4	3.6	3.7	3.9	4.1	1.5%
Rest of World	14.9	14.9	14.4	15.0	16.0	14.9	0.0%
Nonconventional	**2.0**	**4.9**	**6.9**	**8.0**	**9.7**	**11.5**	**7.0%**
North America	1.1	2.3	3.0	3.6	4.5	5.1	5.9%
Rest of World	0.8	2.6	3.9	4.4	5.3	6.4	8.2%
Total	**82.5**	**91.0**	**96.9**	**103.7**	**110.6**	**117.8**	**1.4%**

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, February 2006.

Levels of world oil production and consumption, conventional oil peaking, and the production of non-conventional oil will all play a part in determining future oil prices. Table II-6 lists the EIA-projected prices for both U.S. imported crude oil and U.S. imported low

[1]In addition, the EIA long-range forecasts have generally been the most accurate and reliable; see Ibid.

sulfur light crude oil (LSL) over the next 25 years.[1] Three of the EIA cases have been listed in order to show the huge disparity in the price forecasts. Specifically, the Reference case forecasts oil prices for both imported crude and LSC to increase 1.3 percent per year in real dollars. The optimistic Low-Oil Price case forecasts oil prices to decrease from -0.7 percent to -1.0 percent per year through 2030, while the more pessimistic High-Oil Price case forecasts prices to increase 3.4 percent to 3.6 percent per year. These forecasts likely bound the range of the future price of oil, since the highest prices are three times the level of the low prices in 2030. This disparity also illustrates the pitfalls and difficulties in forecasting future oil prices and in developing appropriate energy policies.

Table II-5.
Forecast of World Oil Consumption to 2030

	2004	**2010**	**2015**	**2020**	**2025**	**2030**	**Annual Growth 2004-2030**
	(million barrels per day)						
United States	20.8	22.2	23.5	24.8	26.1	27.6	1.1%
China	6.6	8.6	9.8	11.4	13.1	14.9	3.2%
Western Europe	13.6	13.4	13.4	13.5	14.0	14.3	0.2%
Other Asia *	6.1	7.6	8.7	9.9	10.9	12.1	2.7%
Middle East	6.1	7.2	7.8	8.3	8.9	9.3	1.7%
South and Central America	5.3	6.3	7.0	7.8	8.4	9.1	2.1%
Former Soviet Union	4.1	4.6	4.7	4.9	5.2	5.4	1.0%
India	2.4	2.9	3.3	3.8	4.3	4.9	2.7%
Africa	3.0	3.6	4.0	4.3	4.6	4.8	1.9%
Japan	5.2	4.9	4.6	4.4	4.3	4.1	-0.9%
Rest of World	9.2	9.8	10.2	10.6	11.0	11.3	0.8%
Total	**82.5**	**91.0**	**96.9**	**103.7**	**110.6**	**117.8**	**1.4%**
* Excluding, FSU, China, India, South Korea							

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, February 2006.

Focusing on average imported crude oil prices, Figure II-4 shows that prices in the Reference case increase from the forecast year base in 2004 of $36 to $50 in 2030. However, that price level was already exceeded in 2005, and oil prices in 2006 were nearly 50 percent higher than that level. The High Oil Price case includes a projected increase to a level of $90 in 2030. Most professional oil industry analysts and forecasters find it hard to give credibility to the Low Oil Price case forecasted by EIA, which shows a decline in the oil price to $28 by 2030 (2004 dollars). As noted in Chapter I, if conventional oil production

[1]EIA now projects prices for both types of oil because its expects imports to continue "souring", becoming heavier and more corrosive in the coming years. This structural shift will force refiners to pay more for higher quality oil.

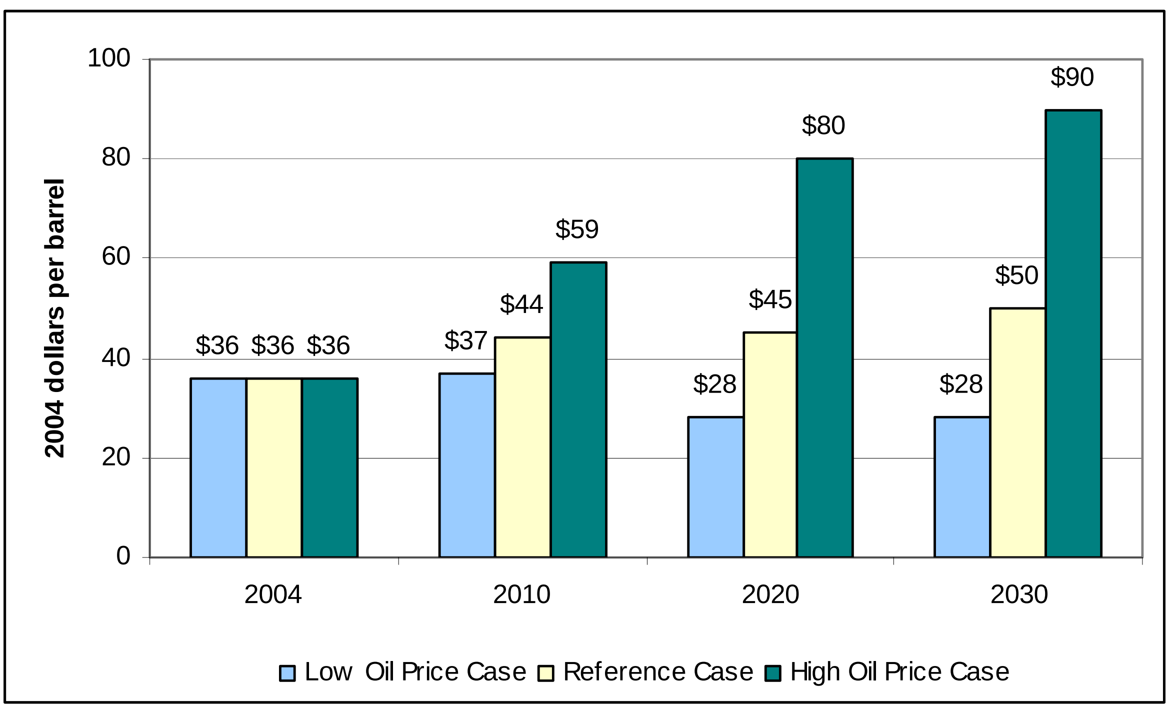
peaks in the near future, even the EIA projected high price of $90/bbl. may be a very low estimate.

Table II-6.
Forecast of World Oil Prices to 2030

	2004	2010	2020	2030	Annual Growth 2004-2030
	(2004 dollars per barrel)				
Imported Crude Oil					
Low Oil Price Case	35.99	37.00	27.99	27.99	-1.0%
Reference Case	35.99	43.99	44.99	49.99	1.3%
High Oil Price Case	35.99	58.99	79.98	89.98	3.6%
Imported Low Sulfur Light Crude Oil					
Low Oil Price Case	40.49	40.29	33.99	33.73	-0.7%
Reference Case	40.49	47.29	50.70	56.97	1.3%
High Oil Price Case	40.49	62.65	85.06	95.71	3.4%

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, February 2006.

Figure II-4.
Forecasts of U.S. Imported Crude Oil Prices to 2030



Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, February 2006.

III. U.S. RESOURCE ASSESSMENT

III.A. Overview

The United States is endowed with quantities of alternative liquid fuel resources that greatly exceed total worldwide conventional oil reserves. Trillions of tons of American coal, oil shale, and renewable biomass resources are available to be converted to premium quality liquid fuels using existing and rapidly emerging technologies; enhanced oil recovery has the potential to produce more than 100 billion barrels of oil from U.S. reservoirs; and transportation energy efficiency and conservation have the combined potential to save millions of barrels per day of liquid fuels.

Coal

America is endowed with the largest coal reserves in the world, and recoverable reserves are estimated to be about 270 billion tons. In 2005 the U.S. produced 1.13 billion tons of coal, second only to China. Based on EIA's 270 billion ton reserve estimate, America has more than 200 years of coal at the current production rate. Even if production were to be doubled, the recoverable reserve base estimated by EIA would last for more than a century. Potential coal reserves are even larger: The demonstrated reserve base is 495 billion tons, identified resources are 1,730 billion tons, and total resources are 4 trillion tons, far more than any other country.

The more detailed report section III.B on "Coal" (below) offers evidence that the widely referenced EIA reserve estimates understate America's true coal potential. Decision makers frequently refer to the EIA 270 billion ton recoverable reserve estimate as being America's coal endowment; however, the EIA total coal resource for the U.S. is nearly 4 trillion tons and the Demonstrated Reserve Base (DRB) is nearly 500 billion tons. Clearly the U.S. endowment of coal is enormous. There is compelling evidence that the 500 billion ton DRB better approximates U.S. coal resources that will ultimately be recovered when advancements in technology, coal reserve growth (as poorly explored measures are added to the DRB), new discoveries, and other dynamics are taken into account.

Oil Shale

The U.S. has very large resources of oil shale, amounting to 2.1 trillion barrels of in-place oil equivalent in the western and eastern parts of the country. By contrast, Saudi Arabian oil reserves are estimated to total about 262 billion barrels, representing about one-fourth of total world conventional oil reserves of about 1.1 trillion barrels. Thus, U.S. oil shale reserves are twice as large as known world oil resources.

Oil shale is sedimentary rock that is dark brown to black in color and high in organic matter. The organic matter is called *kerogen*, fossilized insoluble organic material that will yield liquid and gaseous hydrocarbons upon distillation. The kerogen can be converted into petroleum products by distillation.

U.S. oil shales are concentrated in the western U.S. in the states of Colorado, Utah, and Wyoming, but sizable quantities also exist in the eastern U.S. The most economically attractive deposits, containing an estimated 1.5 trillion barrels of oil equivalent, are found in the Colorado in the Piceance Creek Basin, in Utah in the Uinta Basin, and in Wyoming in the Green River and Washakie Basins. U.S. has by far the greatest oil shale resources in the world.

Enhanced Oil Recovery

Enhanced oil recovery (EOR) technology can significantly increase production from existing U.S. oil reservoirs. Tertiary EOR enhanced recovery methods, including CO_2 EOR, have been practiced in the U.S. since the 1950s. The EOR process having the largest potential is miscible flooding, wherein carbon dioxide (CO_2) is injected into an oil reservoir, providing additional pressure and solvency to move residual oil left over from primary and secondary recovery. U.S. oil resources are very large: Discovered and documented resources amount to 582 billion bbls, 482 billion of light oil and about 100 billion of heavy oil. Approximately 208 billion bbls have been developed, leaving 374 billion bbls still in place, and of these, 80+ billion bbls are estimated to be technically recoverable via EOR.

Biomass

The term ‘biomass’ means any plant derived organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials. Biomass comprises the largest single source of renewable carbon on the planet. Starch from corn and other grains is one type of biomass that currently forms the basis for a large and growing renewable fuel industry.

Commercial ethanol and biodiesel liquid fuels production is well established in the U.S. New biomass-to-liquid fuels process are being developed that offer even greater potential than current ethanol and biodiesil technologies. Cellosic ethanol, pyrolysis and gasification techniques are emerging to cost-effectively produce hydrocarbon fuels from cellulosic biomass resources. The U.S. could sustainably produce over 1.3 billion tons of biomass per year by 2030, according to a recent study by the Oak Ridge National Labs (ORNL). ORNL findings indicate that this resource would be sufficient feedstock to produce about 1/3 of U.S transportation fuels – about five million bpd.

Transportation Energy Efficiency and Conservation

The transportation sector currently accounts for two-thirds of the oil consumed in the U.S. – nearly 15 million bpd, and EIA projects that U.S. liquid fuel consumption by the transportation sector will increase to about 20 million bpd by 2030. The transportation energy efficiency and conservation resource potential is substantial.

Even relatively small annual increases in transportation fuel efficiency over the next two decades could result in very large liquid fuel savings by 2030. Three million barrels of saving per day are possible, and this will help to substantially reduce U.S. oil imports.

III.B. Coal

III.B.1. Rethinking U.S. Coal Reserves and Resources

How much U.S. coal is available for recovery in the near, intermediate and long-term is important knowledge for decision makers as they attempt to guide our country toward energy security and independence. The United States is endowed with the largest coal reserves in the world, and recoverable reserves are estimated by EIA to be about 270 billion tons. In 2005 the U.S. produced 1.13 billion tons of coal, second only to China. Based on the EIA reserve estimate, the U.S. has more than 200 years of coal at current production rates, and even if production were doubled the recoverable reserve base would last for more than a century.

Here we present an overview of U.S. coal resources and offer evidence that the EIA reserve estimates present an understated picture of actual U.S. coal potential. Decision-makers frequently refer to the EIA 270 billion ton recoverable reserve estimate as being the U.S. coal endowment. However, we believe that EIA's 500 billion ton Demonstrated Reserve Base (DRB) estimate is a better approximation of U.S. coal resources that will ultimately be recoverable, considering advancements in technology, coal reserve growth (as poorly explored measures are added to the DRB), new discoveries, and other dynamics.

As part of the research for this report, a questionnaire was sent to coal scientists at state geological surveys or other state agencies that assess coal resources to gather expert knowledge of each state's coal resource, with the goal of evaluating 2004 state-by-state EIA estimates of the DRB. Officials of the USGS and the EIA were also interviewed to gain their perspective, and results from this survey are discussed in Section III.B.5.[1]

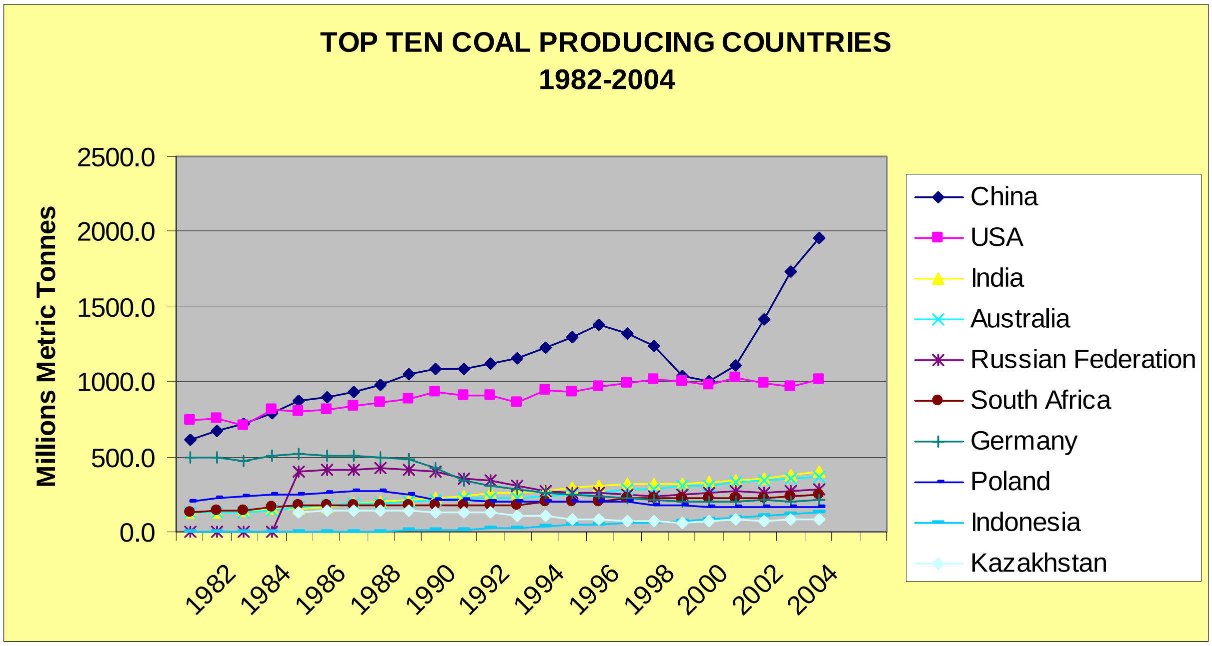
This analysis offers a clearer picture of the magnitude of the U.S. coal endowment, and helps to make the case that the current EIA DRB is perhaps a better indicator of <u>ultimately recoverable</u> U.S. coal reserves. Methods and limitations to the EIA and USGS approaches to coal reserve estimation are outlined herein, with a more in-depth analysis presented in Appendix B. Recommendations to improve current coal reserves estimates and methods are also presented in Appendix B.

The Chinese have not only recognized the strategic significance of their coal resources, but are acting aggressively to realize the full potential of this multi-use fuel and feedstock. China is utilizing coal as a primary fuel source for the production of electricity and steel and has also taken the lead with regard to coal-to-liquids and coal gasification initiatives. Figure III-1 illustrates the rapid growth in Chinese coal

[1]The survey questionnaire and complete survey responses are presented in Appendix C.

production between 2000 and 2004, and China plans to add as much as another billion tons of annual coal production by 2020.[1]

Figure III-1



Source: "BP Statistical Review of World Energy 2005," June 14, 2005.

III.B.2. DOE EIA Coal Reserves and Resources Estimates

U.S coal fields are vast, diverse, and well distributed across the country. DOE reports coal deposits of one or more types or ranks (bituminous, subbituminous, lignite and anthracite) in thirty-three states, as shown in the map of major U.S. coal fields -- Figure III-2. Below is a summary of current U.S. coal reserve/resource estimates by category, published by the DOE EIA. These estimates are discussed in detail throughout this section.

<u>DOE EIA COAL RESERVE/RESOURCE ESTIMATES</u>

Estimated Recoverable Reserves: 267.3 billion tons[2]

Demonstrated Reserve Base: 494.4 billion tons[3]

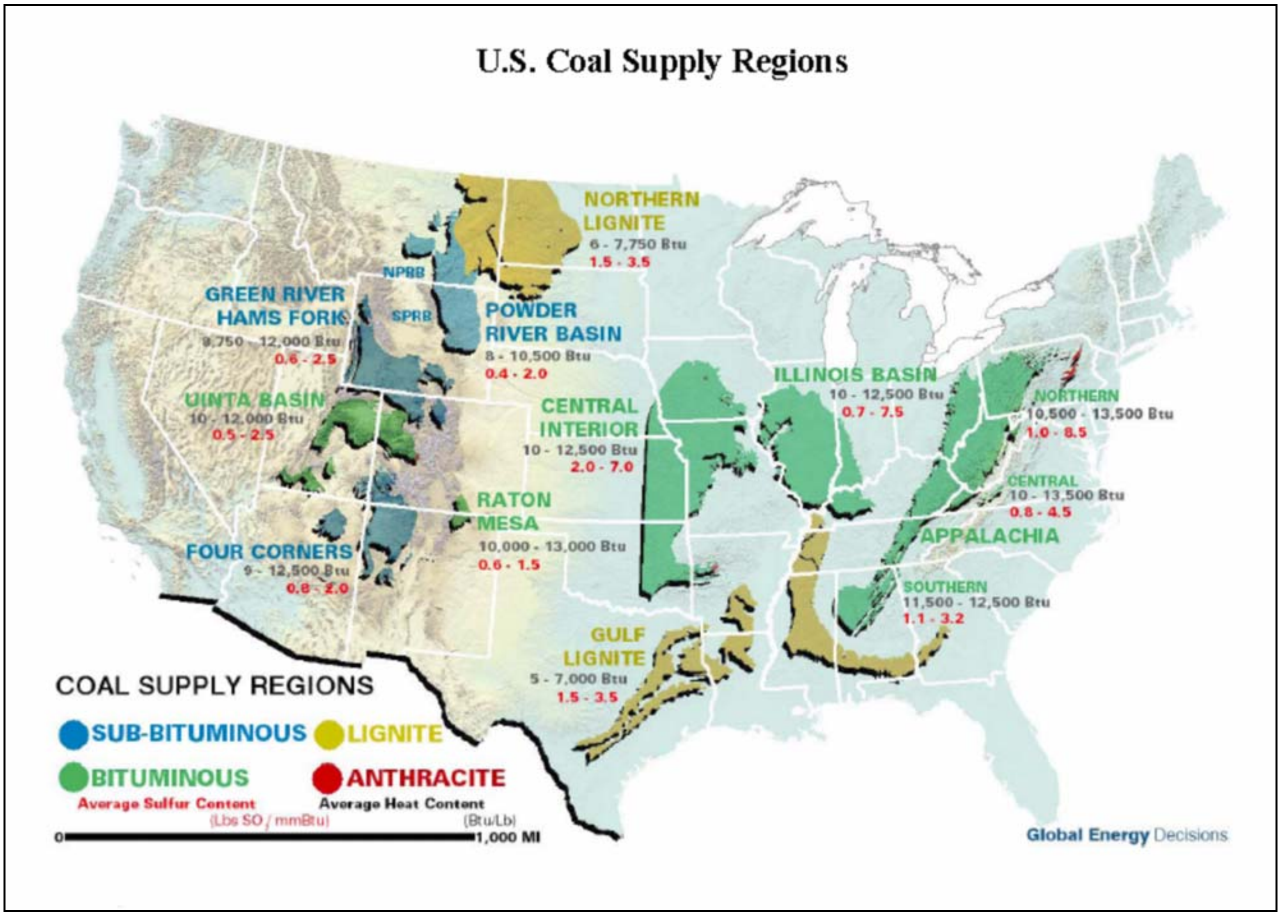
Identified Resources: 1,730.9 billion tons[1]

---

[1]Department of Hi-Tech Development and Industrialization, Ministry of Science and Technology of China, "Development Strategies of China's Energy Technologies," PowerPoint, February 14, 2006, Beijing.
[2]DOE,EIA, "Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method," 2004, Table 15.
[3]Ibid.

Total Resources: 3,968.3 billion tons[2]

Figure III-2



Source: The National Coal Council, "Coal: America's Energy Future," March 2006, Pg. 99

In general, Estimated Recoverable Reserves (ERR) are defined as the portion of the Demonstrated Reserve Base that will be recovered by mining. The Demonstrated Reserve Base (DRB) is comprised of "in-place" coal that meets certain criteria of measurement reliability, and is found within defined depths and in coalbed thicknesses considered technologically minable at the time of determination. An estimate is then made as to what portions of the demonstrated base are accessible and economically recoverable by current mining methods under existing regulatory limits. EIA estimates that approximately 17 percent of the DRB is inaccessible for mining, and that 34 percent of the accessible portion would be unrecovered or lost during mining, leaving 54 percent of the DRB as potentially recoverable. This equates to 268 billion tons of recoverable coal using the recent 494 billion ton DRB estimate. Table III-1 shows EIA 2004

---

[1]EIA, "EIA Coal Reserves Data," [http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html#fig2], 1997. The estimates were actually compiled by the USGS.
[2]Ibid.

estimates for “Estimated Recoverable Reserve” and “Demonstrated Reserve Base” estimates by state and mining method. These numbers are presented for underground and surface mineable coal, and as combined totals.

U.S. coal resources are widely distributed geographically: Approximately 21 percent lie in the Appalachian region; 32 percent in the Interior region; and 47 percent in the Western region -- see Figure III-3. Note that *Eastern* Kentucky is included in the Appalachian region, while *Western* Kentucky (on the Eastern edge of the Illinois Basin) is counted in the Interior region.

Table III-1.
Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method, 2004
(Million Short Tons) [1]

	Underground Minable Coal		Surface Minable Coal		Total	
Coal Resource By State	Estimated Recoverable Reserves	Demonstrated Reserve Base	Estimated Recoverable Reserves	Demonstrated Reserve Base	Estimated Recoverable Reserves	Demonstrated Reserve Base
Alabama	521	1,034	2,285	3,208	2,806	4,242
Alaska	2,745	5,423	545	689	3,291	6,112
Arizona	-	-	5	7	5	7
Arkansas	127	272	101	144	228	417
Colorado	6,050	11,529	3,748	4,764	9,798	16,293
Georgia	1	2	1	2	2	4
Idaho	2	4	-	-	2	4
Illinois	27,944	87,972	10,075	16,557	38,019	104,529
Indiana	3,630	8,764	451	771	4,080	9,534
Iowa	807	1,732	320	457	1,127	2,189
Kansas	-	-	681	973	681	973
Kentucky Total	7,488	17,202	7,516	13,023	15,004	30,225
Eastern	716	1,282	5,244	9,389	5,960	10,671
Western	6,772	15,920	2,273	3,634	9,044	19,554
Louisiana	-	-	316	427	316	427
Maryland	320	584	46	67	366	652
Michigan	55	123	3	5	59	128
Mississippi	-	-	-	-	-	-
Missouri	689	1,479	3,158	4,511	3,847	5,990
Montana	35,922	70,958	39,067	48,322	74,989	119,280
New Mexico	2,848	6,171	4,086	6,001	6,934	12,172
North Carolina	5	11	-	-	5	11
North Dakota	-	-	6,935	9,090	6,935	9,090

[1] EIA, “Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method,” 2004, Table 15.

Ohio	7,733	17,577	3,774	5,765	11,507	23,342
Oklahoma	574	1,232	227	325	801	1,557
Oregon	7	15	2	3	9	17
Pennsylvania Total	10,768	23,330	1,055	4,267	11,822	27,597
Anthracite	340	3,844	420	3,356	760	7,200
Bituminous	10,428	19,486	635	911	11,062	20,397
South Dakota	-	-	277	366	277	366
Tennessee	281	513	180	266	462	779
Texas	-	-	9,578	12,442	9,578	12,442
Utah	2,538	5,177	212	268	2,750	5,445
Virginia	653	1,163	369	576	1,022	1,740
Washington	674	1,332	7	8	681	1,341
West Virginia	15,673	29,366	2,431	3,854	18,104	33,220
Wyoming	22,950	42,501	18,853	21,824	41,804	64,325
U.S. Total	**151,007**	**335,468**	**116,305**	**158,982**	**267,312**	**494,450**

W = Withheld to avoid disclosure of individual company data.

NA = This estimated value is not available due to insufficient data or inadequate data/model performance.

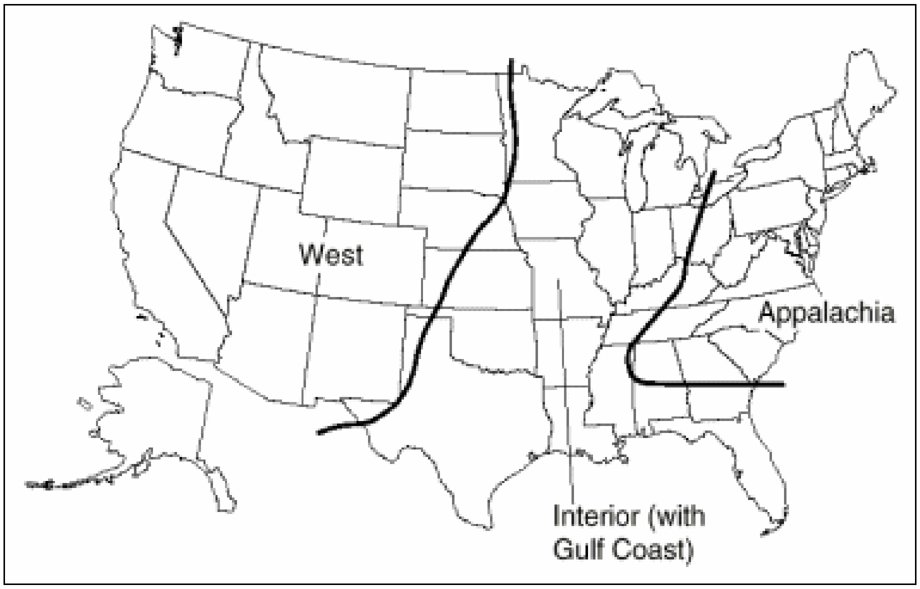
Note: Recoverable coal reserves at producing mines represent the quantity of coal that can be recovered (i.e. mined) from existing coal reserves at reporting mines. EIA's estimated recoverable reserves include the coal in the demonstrated reserve base considered recoverable after excluding coal estimated to be unavailable due to land use restrictions or currently economically unattractive for mining, and after applying assumed mining recovery rates; see “Coal Reserve and Resource Estimate Methodologies” for criteria. The effective date for the demonstrated reserve base, as customarily worded, is "Remaining as of January 1, 2005." These data are contemporaneous with the Recoverable reserves at Producing Mines, customarily presented as of the end of the past year's mining, that is in this case, December 31, 2004. The demonstrated reserve base includes publicly available data on coal mapped to measured and indicated degrees of accuracy and found at depths and in coalbed thicknesses considered technologically minable at the time of determinations; see “Coal Reserve and Resource Estimate Methodologies” for criteria. Excludes silt, culm, refuse bank, slurry dam, and dredge operations except for Pennsylvania anthracite. Excludes mines producing less than 10,000 short tons, which are not required to provide data and refuse recovery.

Data Source: Energy Information Administration Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report," and EIA estimates. http://www.eia.doe.gov/cneaf/coal/page/acr/table15.html

U.S. coal deposits are found in four major types, also known as “rank.” Anthracite comprises approximately 1.5 percent of the DRB, bituminous 53 percent, subbituminous 37 percent, and lignite 8.5 percent. Most of the reserve base is recoverable by underground methods (about 335 billion tons, or 68 percent), and the rest with surface mining (158 billion tons, or 32 percent). Figure III.B.3 illustrates the three coal regions often used to describe where coal occurs and production originates.

The EIA’s current Estimated Recoverable Reserve (EER) projection of approximately 270 billion tons is the most frequently cited measure of “U.S. coal reserves.” The ERR is a calculated percentage of the Demonstrated Reserve Base (DRB), and is currently estimated to be about 54 percent of the DRB average for the entire U.S. As noted, one objective of our reserve analysis is to determine whether EIA's EER estimate represents an accurate measure nation's coal potential.

Figure III-3. U.S. Coal Regions



Source: U.S. Energy Information Administration

The state-by-state coal survey conducted for this report clearly indicates that the 2004 EIA estimates are viewed to be understated – see Section III.B.4. Section III.B.5 offers analysis and insight as to why the EIA DRB estimates fall short of providing a good measure of ultimately recoverable U.S. coal reserves. See Appendix B for more details.

The U.S. is endowed with almost twice the coal resources of the Russian Federation, which has the world's second largest coal reserve base. World coal reserve estimates are presented by country in Table III-2. This table indicates that China has only about half of the coal resources of the U.S., yet it produced approximately 2.2 billion tons in 2005, about twice the U.S. production levels, and has committed to increase output to as much as 3.0 billion annual tons by 2020.   Note that the estimates in Table III.B.2 were compiled by the British energy firm, BP, and are in metric tonnes.[1]

III.B.3. Coal Reserve and Resource Estimate Methodologies

In order to use coal resource estimates for decision making, it is important to understand the methodologies and assumptions that underlie them. Coal resource evaluations and estimation have been conducted by state and federal geological

[1]To convert these to U.S. tons, multiply by 1.10229.

surveys periodically since the beginning of the industrial revolution. Studies are typically sponsored by policy makers in times of national need, such as the Arab Oil Embargo of the early 1970's. This has resulted in new resource estimates every 25 to 50 years.

The U.S. Bureau of Mines (USBOM) and the U.S. Geological Survey (USGS) played central roles in coal resource estimates as facilitators of Congressionally funded programs for geologic mapping in the nation, and as technical advisors to the states. In 1983, the USGS published guidelines and accepted methodology for calculating coal resources in *Coal Resources Classification System of the U.S. Geological Survey*, also known as USGS Circular 891.[1] These methods are almost uniformly used by practitioners in the U.S., including EIA and the state Geological Surveys. They are described below. See Appendix B for more details.

Table III-2

Coal: Proved Reserves at End of 2004[2]
(million metric tonnes)

Table in millions of metric tonnes.	Anthracite and bituminous	Subbituminous and Lignite	Total	Share of total	Reserve-to-Production (R/P) ratio in years of reserves.
USA	111338	135305	246643	27.10%	245
Russian Federation	49088	107922	157010	17.30%	*
China	62200	52300	114500	12.60%	59
India	90085	2360	92445	10.20%	229
Australia	38600	39900	78500	8.60%	215
South Africa	48750	-	48750	5.40%	201
Ukraine	16274	17879	34153	3.80%	424
Kazakhstan	28151	3128	31279	3.40%	360
Other Europe & Eurasia	1529	21944	23473	2.60%	341
Poland	14000	-	14000	1.50%	87
Brazil	-	10113	10113	1.10%	*
Germany	183	6556	6739	0.70%	32
Colombia	6230	381	6611	0.70%	120
Canada	3471	3107	6578	0.70%	100
* More than 500 years					Source: World Energy Council
◆ Less than 0.05%					
Notes:					
Proved reserves of coal - Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions.					
Reserves/Production (R/P) ratio - If the reserves remaining at the end of the year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level.					

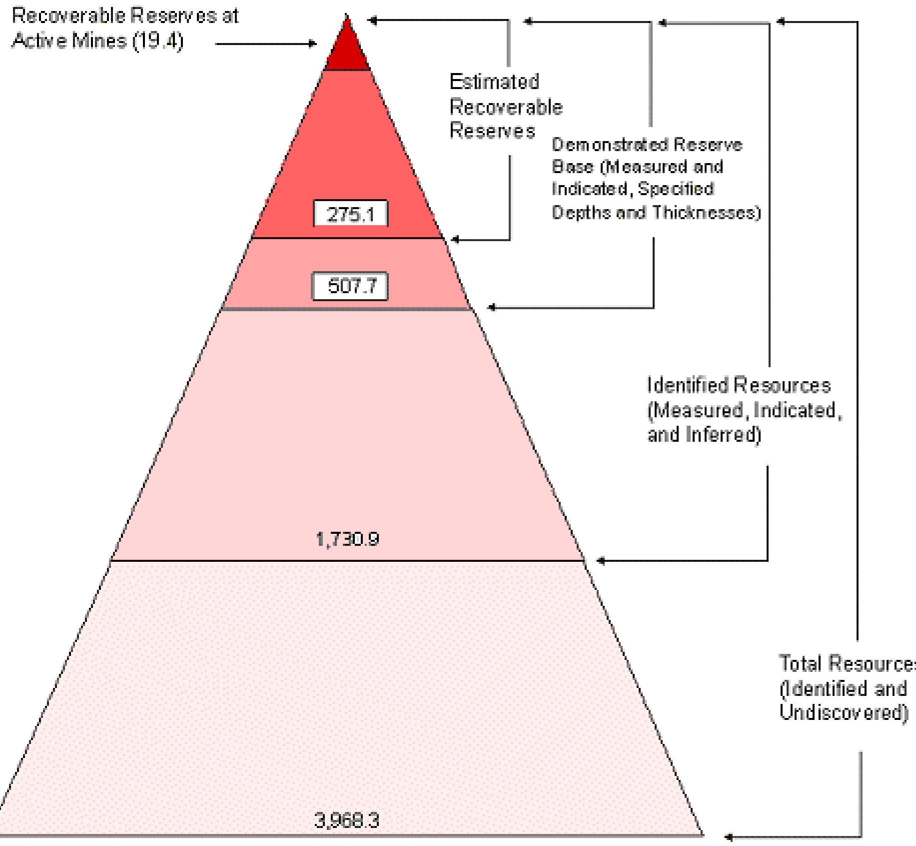
Note: 1 metric tonne = 1.10229 U.S. tons and 1 U.S. ton = 0.9072 metric tones.

[1]Wood, G.H., Jr., Kehn, T.M., Carter, M.D., and Culbertson, W.C., 1983, Coal resource classification system of the U.S. Geological Survey: USGS Circular 891.

[2]"BP Statistical Review of World Energy 2005," June 14, 2005.

Figure III-4 illustrates how coal resources are generally classified in the U.S.

Figure III-4.
Delineation of U.S. Coal Resources and Reserves
(billions of short tons)[1]



Resources and reserves data are in billion short tons. Darker shading in the diagram corresponds to greater relative data reliability. The estimated recoverable reserves depicted near the top of the diagram assume that the 19 billion short tons of recoverable reserves at active mines reported by mine operators to EIA are part of the same body of resource data. This diagram portrays the theoretical relationships of data magnitude and reliability among coal resource data. All estimates are subject to revision with changes in knowledge of coal resource data.
Data Sources: The DRB estimate was compiled by the EIA as of 1-1-97. Estimated recoverable reserves were compiled in EIA's Coal Reserves Data Base program. Recoverable reserves at active mines were reported in EIA's *Coal Industry Annual*, 1996. Identified resources and total resources are estimates as of 1-1-74, compiled and published by the U.S. Geological Survey in *Coal Resources of the United States*, January 1, 1974.

From top to bottom, the pyramid generally represents reserves/resource estimates by diminishing degree of confidence in data reliability. The top two categories, "Recoverable Reserves at Active Mine" and "Estimated Recoverable Reserves," are estimates of tonnage that is available to be recovered by current mining

[1]EIA, "EIA Coal Reserves Data," 1997.

practices. The lower categories are estimates of “in-place” coal resources, before applying a recovery factor. The resource pyramid in this figure is based on older data; however, although dated, the graphic has been included to introduce the current approach to classifying coal reserves and resources.

Figure III-5 illustrates how proven, indicated, and inferred reserves are measured – additional detail is presented on reserve measurement and classification in Appendix B. While USGS Circular 891 permits practitioners to specify customized dimensions for reliability circles to reflect the variability of the deposits, most states use the recommended ¼-, ¾-, and 3-mile data spacings (Measured, Indicated and Inferred, respectively) to facilitate comparisons with other estimates. This means that reserves falling from ¾ of a mile to 3 miles from a coal measurement (drill hole, outcrop, etc.) are classified as Inferred, and anything outside of a 3 mile radius falls into the Undiscovered category.

In Figure III-5 it is evident that the vast majority (about 2.5 trillion tons) of EIA’s total estimated U.S. coal resources are not included in the Demonstrated Reserve Base (DRB), and the principal reason for this is that they fall into the Identified and Undiscovered reserve classifications. It is believed highly likely that a sizable portion of these non-DRB coal measures will ultimately be recoverable based on the development of more reserve data and through the advancement of coal recovery and utilization technologies.

Alaska provides a dramatic example of unrecognized coal potential, as estimated by EIA. Total estimated coal resources in Alaska are approximately 5.5 trillion short tons, according to the most recent comprehensive State coal resource assessment.[1] By comparison, the EIA/USGS estimate of total U.S. resources is only 3.9 trillion tons. Alaska accounts for a meager 6.1 billion tons in the EIA’s 2004 DRB estimate, even though a number of state experts believe that coal reserves and resources in Alaska rival those in the collective lower 48 states. This certainly reinforces the possibility that EIA’s 500 billion ton DRB estimate is a better approximation of ultimately recoverable U.S. coal reserves.

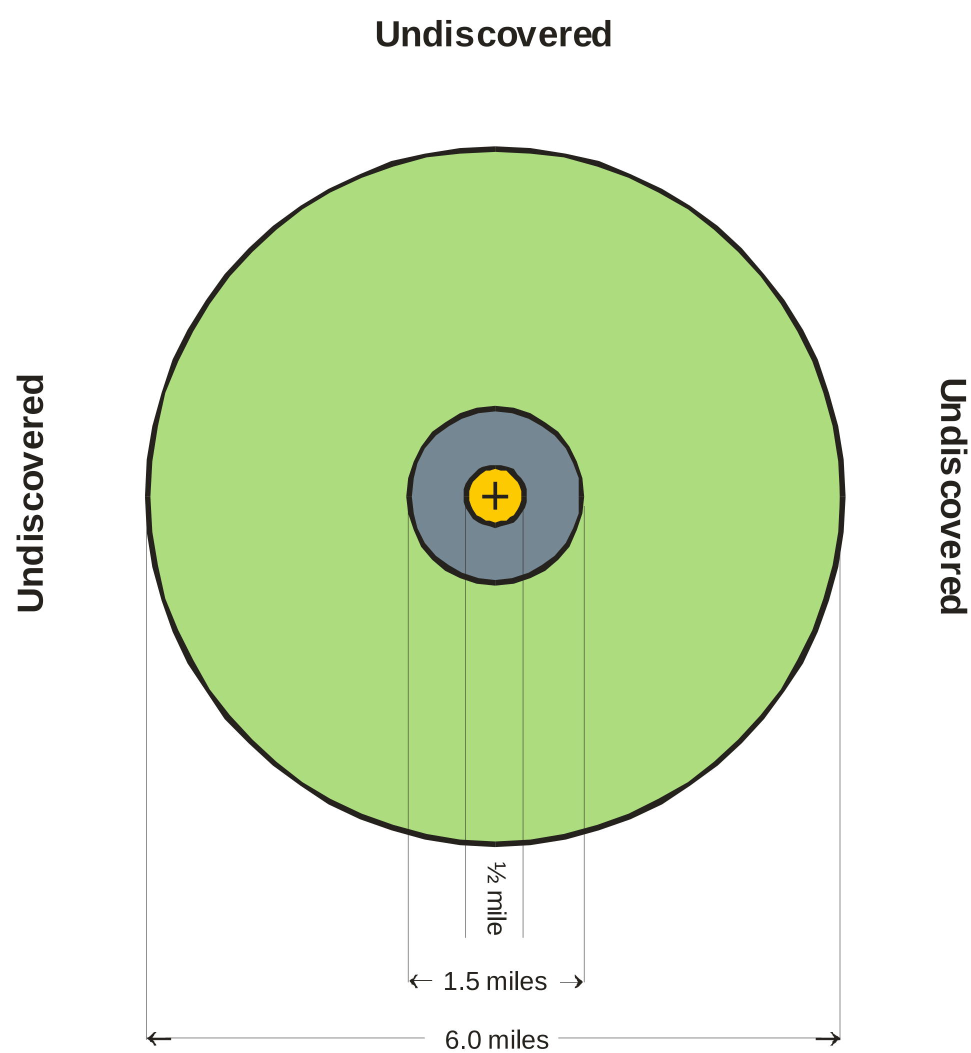
III.B.4. Limitations of DOE EIA Estimates

As previously noted, EIA’s “Estimates Recoverable Reserve” value of 270 billion tons is not believed to accurately reflect the true potential of the U.S. coal endowment, and this is unfortunate, as many policymakers rely on this estimate for intermediate and long-range planning. With the role of coal expected to expand materially through the rapid emergence of coal-to-liquids and coal-to-gas production in the U.S., and with future electric generating needs anticipated to be substantially coal fired, we believe a more accurate and dynamic approach to coal reserve estimation is required. To this end, recommendations for improving these estimates are presented in Appendix B. These may prove useful as a guide to EIA, the USGS, and the states.

---

[1] Alaska Department of Natural Resources in cooperation with the Alaska Coal Association, “Map of Alaska Coal Resources,” compiled by R.D. Merritt and C.C. Hawley, 1986.

Figure III-5. Measured, Indicated and Inferred Areas Around a Coal Observation/Exploration Point



+	Observed data point:	exploration drillhole, outcrop, oil/gas well, or water well.
(yellow)	Proven Resources:	¼ mile radius from observed datapoint. ½ mile diameter from observed data-point to observed datapoint.
(grey)	Indicated Resources:	½ mile wide band around the Proven Reserve radius.
(green)	Indicated Resources:	2.25 mile wide band around the Indicated Reserve radius.

Source: A. J. Mayer International

III.B.5. State-by-State Coal Resource Survey Results

All 33 states reported by EIA to have coal resources were surveyed as part of this study to determine, among other things, whether each believed the EIA Demonstrated Reserve Base (DRB) was representative for the state. This survey and all responses are presented in Appendix C. We attached to each state survey a table containing the EIA 2004 DRB estimate for the state and Identified Resources (based on state data) contained in the 2002 Keystone Industry Coal Manual.[1] One of the questions asked in the survey was whether the EIA DRB or the Keystone Identified Resource projection best reflected the state's current estimate of the actual DRB. A narrative discussing select survey results follows, beginning with reserve highlights. The color coding in Table III-3 corresponds to the right-hand column of Table III.4. Thirty-three states were surveyed and nineteen states responded. Of the responses:

Color Code
For Table III.B.4

Table III-3. State Responses

And 9 states provided DRB estimates exceeding current EIA estimates by 275 billion tons.

2 states, Alaska and Louisiana, indicated that "Identified Resources" as published in the Keystone Coal Industry Manual[2] was a better indicator of the DRB.

7 states noted that their estimate of the DRB exceeds the EIA estimate, but gave no number.

And 16 states in total indicated that the DRB should be higher than the EIA estimate.

1 state, Virginia, reported that the EIA DRB was representative.

1 state, Illinois reported a slightly lower numeric estimate DRB estimate than the EIA.

1 state, Pennsylvania, provided an indication that the EIA DRB for their State was overstated.

Sixteen of the 19 responding states indicated that the EIA DRB was understated, representing 84 percent of the returned surveys. One state indicated that the EIA DRB was representative. And two states out of 19 indicated that the EIA estimate was too high. The right hand column of Table III.B.4 contains the states' responses to the questionnaire with respect to whether they felt the DRB or Identified Resources was the best estimate of the state's coal resources. Most states responded that the DRB was the closest figure, but that it excluded some resources that would be mineable. The label "> DRB" implies that the state would use an estimate somewhat greater than the DRB, but significantly less than the Keystone value. Appendix B contains a more in-depth presentation and analysis of the state survey responses. Appendix C presents the survey questions and a complete set of state answers to each question.

[1]Keystone Coal Industry Manual, 2002, Steve Fiscor, ed.: CoalAge, Primedia, Chicago.
[2]Ibid.

Table III-4: State-By-State Coal Reserve Analysis (in millions of tons unless otherwise noted)

State	2004 EIA Production (000s)	2004 EIA Estimated Recoverable Reserves (ERR)	2004 EIA ERR/DRB %	2004 EIA Demonstrated Reserve Base (DRB)	Current State DRB Estimate	Difference Between EIA and Current State DRB	DRB Adjustment Assuming EIA Recovery %	2002 Identified Resources (Keystone)	State Response to 2004 EIA DRB or Keystone Identified Resource
Wyoming	396,493	41,804	64.99%	64,325				1,431,430	> 2004 EIA DRB
West Virginia	147,993	18,104	54.50%	33,220				94,618	> 2004 EIA DRB
Kentucky Total	114,244	see Kentucky, Eastern and Western							
Kentucky, Eastern	90,871	5,960	55.85%	10,671	18,900	8,229	4,596	53,400	18.9 BT *
Pennsylvania	65,996	11,822	42.84%	27,597				78,000	< DRB
Texas	45,863	9,578	76.98%	12,442				56,384	No response
Montana	39,989	74,989	62.87%	119,280				291,600	> 2004 EIA DRB
Colorado	39,870	9,798	60.14%	16,293	20,000	3,707	2,229	434,000	> 20 BT
Indiana	35,110	4,080	42.79%	9,534	59,500	49,966	21,383	34,059	59.5 BT
Illinois	31,853	38,019	36.37%	104,529	96,000	-8,529	-3,102	199,151	96 BT (available)
Virginia	31,420	1,022	58.74%	1,740				NA	DRB
North Dakota	29,943	6,935	76.29%	9,090	25,000	15,910	12,138	350,911	25 BT
New Mexico	27,250	6,934	56.97%	12,172				39,466	> 2004 EIA DRB
Kentucky, Western	23,373	9,044	46.25%	19,554	34,300	14,746	6,820	36,022	34.3 BT *
Ohio	23,222	11,507	49.30%	23,342				39,470	No response
Alabama	22,271	2,806	66.15%	4,242				23,461	> 2004 EIA DRB
Utah	21,746	2,750	50.51%	5,445				42,560	> 2004 EIA DRB
Arizona	12,731	5	71.43%	7	21,250	21,243	15,174	NA	21.25 BT
Washington	5,653	681	50.78%	1,341				6,861	No response
Maryland	5,225	366	56.13%	652				852	No response
Louisiana	3,805	316	74.00%	427	1,700	1,273	942	1,700	Identified
Mississippi	3,586	0	50.00% est.	0	5,000	5,000	2,500	NA	5 BT
Tennessee	2,887	462	59.31%	779			0	NA	No response
Oklahoma	1,792	801	51.45%	1,557			0	8,068	No response
Alaska	1,512	3,291	53.84%	6,112	169,824	163,712	88,151	169,824	Identified
Missouri	578	3,847	64.22%	5,990	7,630	1,640	1,053	NA	4.9 BT recoverable
Kansas	71	681	69.99%	973				53,000	>DRB (no underground)
Arkansas	7	228	54.68%	417					No response
Georgia	0	2	50.00%	4					No response
Idaho	0	2	50.00%	4					No response
Iowa	0	1,127	51.48%	2,189					No response
Michigan	0	59	46.09%	128					No response
North Carolina	0	5	45.45%	11					No response
Oregon	0	9	52.94%	17					No response
South Dakota	0	277	75.68%	366					No response
TOTALS		267,311	54.06%	494,450		276,897	151,884		

Notes to Table III-4:

EIA Production by State: EIA "Coal Production and Number of Mines by State and Mine Type," 2004
http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html

EIA Estimated Recoverable Reserves (ERR) and Demonstrated Reserve Base (DRB):
http://www.eia.doe.gov/cneaf/coal/page/acr/table15.xls

Identified Resources: Reported by the states to the Keystone Coal Industry Manual, 2002

*Kentucky Geological Survey estimate of ultimate DRB, or resources ultimately available to mine -- does not strictly conform to USGS Circular 891 DRB guidelines.

III.C. Oil Shale

III.C.1. U.S. Oil Shale

Oil shale is sedimentary rock that is dark brown to black in color and high in organic matter. The organic matter is called *kerogen*, fossilized insoluble organic material that will yield liquid and gaseous hydrocarbons upon distillation. The kerogen can be converted into petroleum products by distillation. The shale must be heated, typically in a closed vessel (retort), to about 500° C to convert it into petroleum. Oil shales of commercial grade generally yield between 20 and 50 gallons of oil per short ton of shale rock.

The United States has very large resources of oil shale, amounting to 2.1 trillion barrels of in-place oil equivalent in the western and eastern parts of the country (Table III-5). U.S. oil shales are concentrated in the western U.S. in the states of Colorado, Utah, and Wyoming, but sizable quantities also exist in the eastern U.S. -- Figure III-6 shows the extent of oil shale-bearing formations in the U.S. The most economically attractive deposits, containing an estimated 1.5 trillion barrels of oil equivalent, are found in the Green River Formation of Colorado in the Piceance Creek Basin, in Utah in the Uinta Basin, and in Wyoming in the Green River and Washakie Basins.

Table III-5
U.S. Oil Shale Resources Estimates in Barrels of Oil Equivalent

	In-Place Oil Shale Resources (thousands of barrels)
Eastern oil shale: Kentucky, Ohio, Indiana	189,000
Green River Formation: Colorado, Utah, Wyoming	1,499,000
Other Western Resources	430,228
Total U.S.	2,118,228

Source: J.R. Dyni, "Oil Shale Deposits of the U.S.," *Oil Shale Journal*, vol. 20, no. 3, 2003.

In Particular:

- Colorado has 1.2 trillion barrels of oil shale resources, and five projects are currently being reviewed for environmental impact statements by the Bureau of Land Management under their oil shale RD&D program. Shell has three projects, Chevron/Texaco has one, and EGL has one. The EIS is also underway for commercial leasing in 2007 or 2008.
- Utah has substantial oil shale resources and BLM has recently granted one company the right to proceed to a pilot project. The USGS has had an oil shale data compilation project in Utah for the last two years.

Figure III-6
Principal Reported Oil Shale Deposits of the United States

Source: *Final Environmental Statement for the Prototype Oil Shale Leasing Program*, U.S. Department of the Interior, Bureau of Land Management, Volume I, 1973.

- In the eastern U.S., oil shale underlies the Appalachian, Illinois, and Michigan Basins, predominantly in Devonian age deposits covering hundreds of thousands of acres from Illinois to New York to Alabama, and it is estimated that there are 189 billion barrels of oil equivalent in Eastern oil shale.[1] Kentucky has the largest outcrop of oil shale in the eastern U.S. and also has the largest amount of surface and near-surface oil shale. A two county area in eastern

[1]Dyni, op. cit.

Kentucky was investigated in detail in the 1980s and was estimated to contain 4.4 billion barrels of oil equivalent with 1.3 billion barrels in a stripping ratio of 2.5:1.

Fisher assay is the most common method of ranking oil shale in terms of potential oil produced. Oil yields generally vary from 10 to 50 gallons per ton and some oil shale is as high as 65 gal/ton, Shales yielding more than 25 gal/ton are the most attractive and are considered to be potential resources.

III.C.2. Characteristics of U.S. Oil Shale Resources

The extent and characteristics of U.S. western oil shale resources, and particularly those in the Green River Formation, are well known and documented.[1] Oil shale is a hydrocarbon bearing rock that is generally shallower (<3000 feet) than the deeper and warmer geologic zones required to form oil. The origins of oil shale can be categorized into three basic groups: Terrestrial (organic origins similar to coal-forming swamps), lacustrine (organic origins from fresh or brackish water algae), and marine (organic origins from salt water algae, acri-tarchs, and dinoflagellates).[2]

Worldwide, the oil shale resource base is believed to contain about 2.6 trillion barrels, of which the vast majority, over two trillion barrels, (including eastern and western shales), is located within the United States.[3] The most economically attractive deposits, containing an estimated 1.5 trillion barrels (richness of >10 gal/ton) are found in the Green River Formation of Colorado (Piceance Creek Basin), Utah (Uinta Basin) and Wyoming (Green River and Washakie Basins).

The richest eastern oil shales underlie approximately 850,000 acres of land in Kentucky, Ohio, and Indiana. Other eastern states have oil shale resources as well (see map III.C1). Sixteen billion barrels, at a minimum grade of 20 gal/ton, are located in the Kentucky Knobs region in the Sunbury shale and the New Albany/Ohio shale. Due to differences in kerogen type (compared to western shale), eastern oil shale requires different processing. However, with processing technology advances, potential oil yields from eastern shales could someday approach yields from western shales.

Figure III-7 illustrates the most concentrated areas of western resources. More than a quarter million assays have been conducted on core and outcrop samples for the Green River oil shale, and results have shown that the richest zone, known as the Mahogany zone, is located in the Parachute Creek member of the Green River Formation. This zone can be found throughout the formation.

---

[1]Anton Dammer, Office of the Deputy Assistant Secretary for Petroleum Reserves, Office of Naval Petroleum and Oil Shale Reserves, U.S. Department of Energy Washington, D.C., *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resources, Technology and Economics*, March 2004, pp. 2-5.
[2]Dyni, op. cit.
[3]Ibid.

A layer of volcanic ash several inches thick, known as the Mahogany marker, lies on top of the Mahogany zone and serves as a convenient stratigraphic event that allows oil shale beds to be correlated over extensive areas. Because of it's relatively shallow nature and consistent bedding, the resource richness is well known, giving a high degree of certainty as to resource quality.

By assay techniques (Fischer assay being the commonly accepted method) oil yields vary from about 10 gal/ton to 50 gal/ton and, for a few feet in the Mahogany zone, up to about 65 gal/ton. Oil shale yields of more than 25 U.S. gal/ton are generally viewed as the most economically attractive, and thus the most favorable for initial development.

Figure III-7
Oil Shale Areas in Colorado, Wyoming and Utah

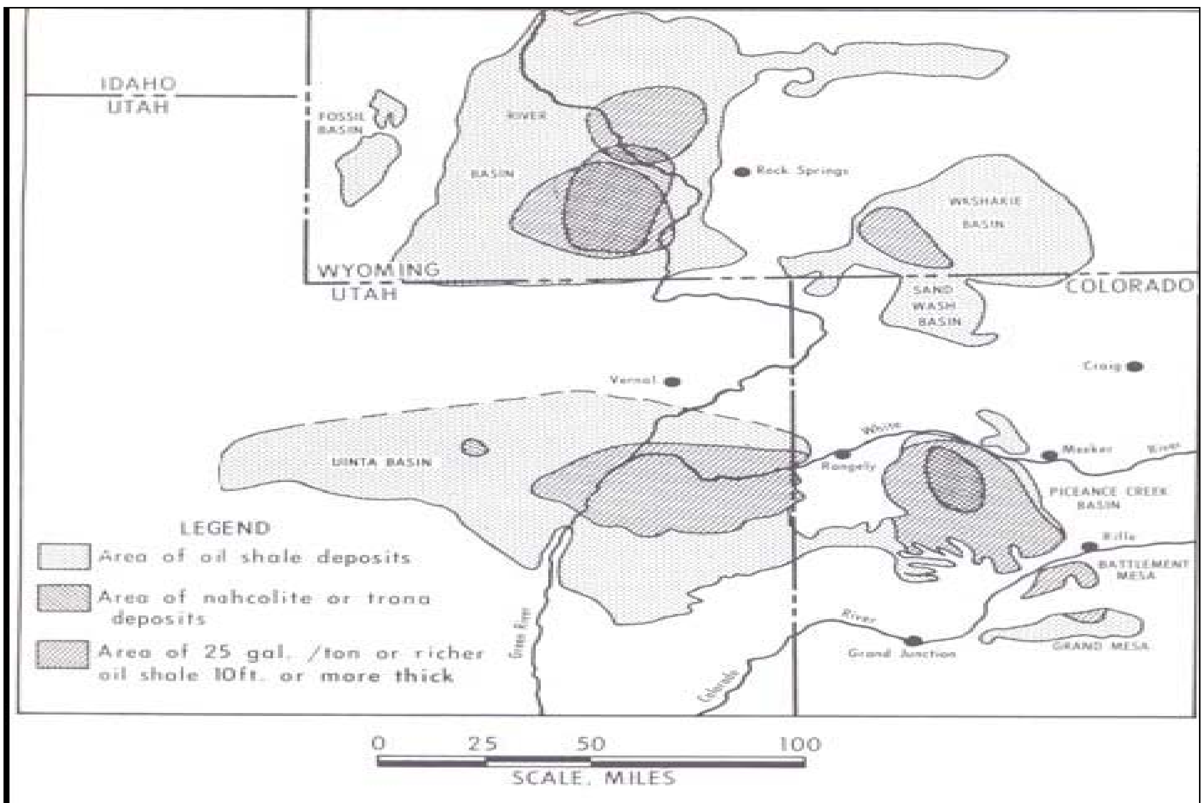
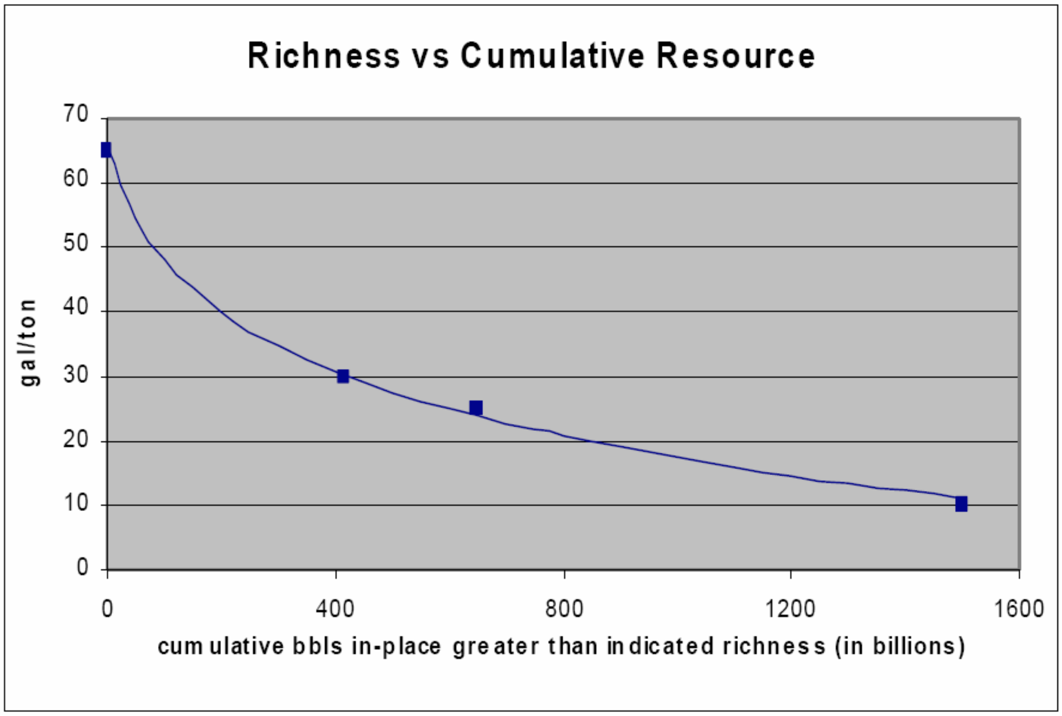


FIGURE I-1.--Oil Shale Areas in Colorado, Utah, and Wyoming.

Source: Final Environmental Statement for the Prototype Oil Shale Leasing Program, U.S. Department of the Interior, Bureau of Land Management, Volume I, 1973.

When discussing oil shale resources, it is also important to qualify the resource estimates by richness. Of the 1.5 trillion barrels of western oil shale resources, an estimated 418 billion barrels are in deposits that will yield at least 30 gal/ton in zones at least 100 feet thick,[1] and there are estimated resources of 750 billion barrels at 25 gal/ton in zones at least 10 feet thick.[2] These data correlate well with the logarithmic curve form illustrated in Figure III-8.

Figure III-8
Cumulative Resource Greater Than Indicated Richness



Oil shale resources lie within the basin with low dip in the general direction of prevailing regional drainages, and oil shale generally outcrops along the eroded margins of the basin, yielding multiple access points. The thickest, richest zones are found in the north-central portions of the Piceance Creek and northeastern Uinta Basins. In general, surface mining is likely to be used for those zones that are near the surface or that are situated with an overburden-to-pay ratio of less than about 1:1. Economic optimization methods can be used to select stripping ratios, optimum intercept, and cutoff grades.

Oil shale exhibits distinct bedding planes, which can be used to advantage during mining and crushing operations. Shear strengths along the bedding planes are considerably less than across the plane, thereby reducing operational demands.[3]

---

[1]W.J. Culbertson and J.K. Pitman, “Oil Shale,” in United States Mineral Resources, USGS Professional Paper 820, Probst and Pratt, eds., 1973, pp. 497-503.
[2]J.R. Donnell, “Geology and Oil-Shale Resources of the Green River Formation,” *Proceedings, First Symposium on Oil Shale*, Colorado School of Mines, pp. 153-163, 1964.
[3]Cameron Engineers, *Synthetic Fuels Data Handbook*, 1975.

Thin overburden, attractive for surface mining, tends to be found along part of the margins of the southern Uinta Basin and the northern Piceance Creek Basin, and the decision as to how deep or selective to mine is an economic optimization issue. Numerous opportunities exist for the surface mining of ore averaging more than 25 gallon/ton, with overburden-to-pay ratios of less than one, especially in Utah. Attractive locations in Colorado are found at the north end and along the southern flank of the Piceance Creek basin, and zones 25 feet thick or more, with yields of 35 gallon/ton can be found throughout this area. In Utah, opportunities for 35 gallon/ton ore exist along Hell's Hole canyon, the White River, and Evacuation Creek.

In general, room and pillar mining is likely to be used for resources that outcrop along steep erosions, and horizontal room and pillar mining has been used successfully by Unocal. Deeper and thicker ores will require vertical shaft mining, modified in-situ, or true in-situ recovery approaches. Because the pay zone is more than 1,500 feet thick in some places, it is conceivable that open pit mining could be applied even with 1,000 feet of overburden.

In recent years, Shell has experimented with a novel in-situ process, that shows promise for recovering oil from rich, thick resources lying beneath several hundred to 1,000 feet of overburden. There are locations that could yield in excess of 1 million barrels per acre and require, with minimum surface disturbance, fewer than 23 square miles to produce as much as 15 billion barrels of oil over a 40 year project lifetime. In addition, in the northern Piceance Creek basin, zones of high grade oil shale also contain rich concentrations of nahcolite and dawsonite -- high-value minerals that could be recovered through solution mining.

III.D Enhanced Oil Recovery

III.D.1. Primary and Tertiary Recovery

Crude oil production occurs via a series of oil "crops" called primary (1st crop), secondary (2nd crop), and tertiary (3rd crop). Enhanced oil recovery (EOR) is a term often used to describe tertiary recovery, but should be reserved for the more advanced oil production technologies regardless of where the process occurs in the sequence of oil crops. For example, thermally enhanced recovery of tars or heavy oils utilizes advanced technologies for the first or second crops of oil from a given resource.

Primary oil recovery is often the least efficient method in terms of the percent of original oil in place (OOIP) recovered, unless the reservoir has an active aquifer providing the driving force. Sometimes only five or 10 percent of OOIP is produced during primary recovery, especially in the case of low-pressure, shallow reservoirs with only small amounts of internal energy to force the oil out. After primary production has been completed, reservoirs require additional (secondary) energy sources to recover the oil left behind. Secondary oil recovery techniques historically have referred to the injection of gas or water to displace oil and drive it to a production well, and secondary recovery often yields as much as or more oil than primary recovery. Well-designed water floods may recover 20 to 40 percent of the OOIP, depending on oil and reservoir characteristics, leaving "residual oil" amounting to perhaps 50 percent of the OOIP.

Theoretically, EOR techniques offer prospects for producing up to 100 percent of the residual oil under nearly-perfect reservoir conditions; however, practically speaking, the additional recovery is more likely to be similar to the amount of oil recovered during secondary recovery activities. Three major categories of EOR have been found to be commercially successful to varying degrees:

- Thermal recovery (e.g., steam injection) introduces heat into the reservoir to lower the oil's viscosity, thereby improving the oil's ability to flow from the reservoir. Thermal techniques account for over 50 percent of the U.S. EOR production.
- Gas injection uses gases such as natural gas, nitrogen, or carbon dioxide to displace additional oil from the reservoir or to dissolve in the oil causing it to expand while simultaneously lowering its viscosity, both of which improve the oil's ability to flow from the reservoir. Gas injection accounts for close to 50 percent of U.S. EOR production.
- Chemical injection may be used to enhance the characteristics of the water in a water flood, either to increase the water's viscosity, making it less likely to by-pass reservoir oil and leaving part of the oil behind, or to lower the interfacial tension between the water and the oil, "lubricating" the path for the oil to flow from the reservoir. Chemical techniques account for less than one percent of U.S. EOR production.
- Other processes, such as microbial EOR, are being researched, but do not currently contribute significantly to oil production.

Each of these techniques involves costs that are higher than typical conventional secondary recovery methods and involve additional risk because of the sensitivity of the processes to some of the reservoirs' unknown characteristics.

III.D.2 EOR Resources

As shown in Table III-6, U.S. oil resources are very large. The problem is in recovering them. Discovered and documented resources amount to 582 billion bbls, 482 billion of light oil and about 100 billion of heavy oil. Approximately 208 billion bbls have been developed, leaving 374 billion bbls still in place. Of these 374 billion bbls of oil-in-place, at least 100 billion bbls are estimated to be producible via EOR (see Table III-6 note). These numbers do not include projected reserves growth (RG), undiscovered resources (UR), residual oil zone resources (ROZ), or oil sands.

Table III-6 U.S. Domestic Oil Resources **(DOE Fact Sheet, 2006)**

Original, Developed and Undeveloped Domestic Oil Resources (Billion Barrels)*						
				Future Recovery**		
	Original Oil In- Place	Developed to Date	Remaining Oil In-Place	Conventional Technology	EOR*** Technology	Total
I. Crude Oil						
1. Discovered	**582**	**(194)**	**374**	-	**100**	**100**
• Light Oil	482	(189)	293	-	80	80
• Heavy Oil	100	(19)	81	-	20	20
2. Undiscovered	**360**	-	**360**	**119**	**60**	**179**
3. Reserve Growth	**210**	-	**210**	**71**	**40**	**111**
4. Residual Oil Zone	**100**	-	**100**	-	Unknown	Unknown
II. Tar Sands	**80**	-	**80**	-	**10**	**10**
TOTAL	**1,332**	**(194)**	**1,124**	**190**	**210**	**400**

**Does not include oil shale. **Technically recoverable resources rounded to the nearest 10 billion barrels.*
**** Based on six basin-oriented assessments released by DOE in April 2005.*

Note: The above estimates, based on earlier work, do not include the additional resource potential outlined in ten basin-oriented assessments or recoverable resources from residual oil zones, as discussed in related reports issued by DOE in February 2006. Accounting for these, the future recovery potential from domestic undeveloped oil resources by applying EOR technology is 240 billion barrels, boosting potentially recoverable resources to 430 billion barrels.

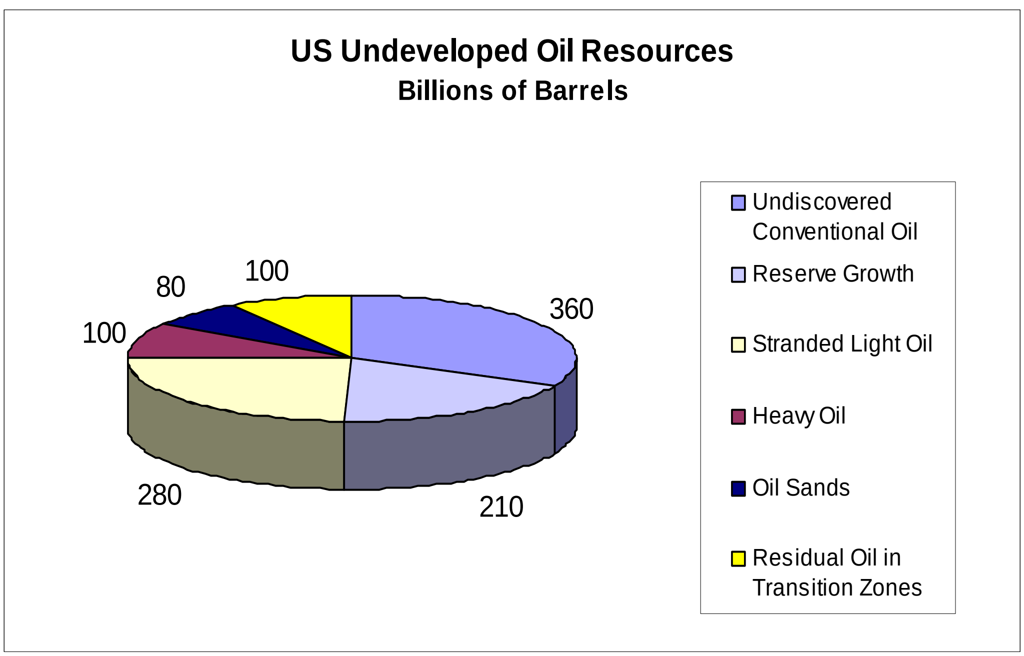


Figure III-9. Undeveloped U.S. Oil Resources (DOE Fact Sheet: **"**Recovery of Undeveloped Domestic Oil Resources Can Provide the Foundation for Increasing U.S. Oil Production")

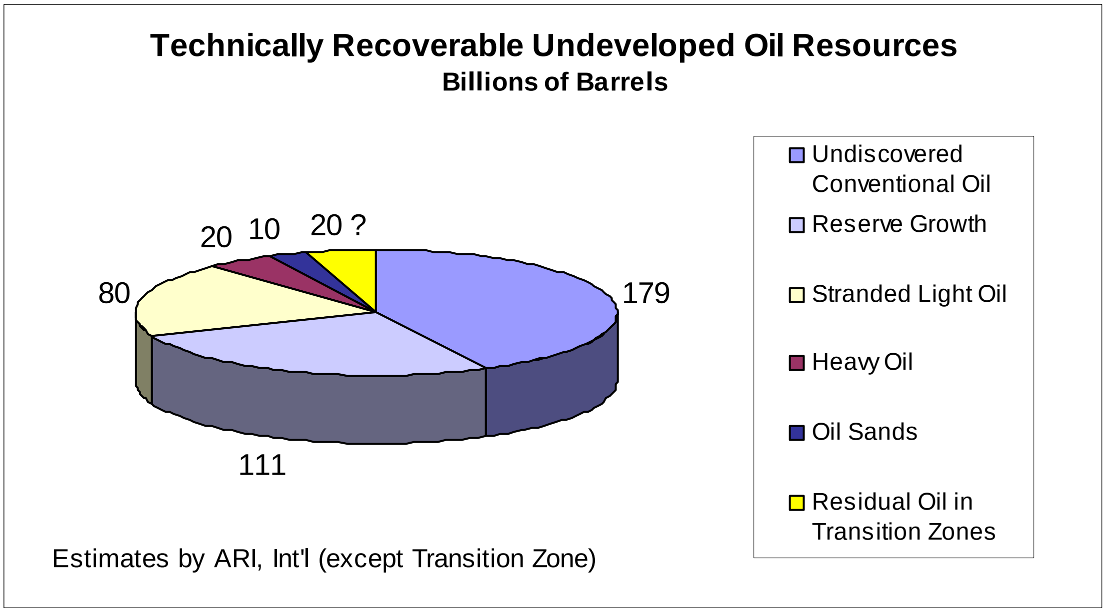


Figure III-10. Technically Recoverable U.S. Oil Resources (DOE Fact Sheet: **"**Recovery of Undeveloped Domestic Oil Resources Can Provide the Foundation for Increasing U.S. Oil Production")

Beyond this point in the analysis, estimates of future oil recovery are based mostly on statistical analysis. While the statistical bases for the projections are sound and there is a statistically high probability that the projections will be borne out, there are no guarantees. That said, there could very well be another 430 billion bbls of oil produced in the future, including 179 billion bbls from undiscovered resources (UR), 111 billion from reserve growth (RG), and 10 billion from oil/tar sands, plus the 30 billion-bbl correction to the EOR potential from the four additional basins that were evaluated after Table III-6 was created -- see note in the table. A similar analysis of undeveloped U.S oil resources is shown in Figures III-9 and III-10. These figures may differ somewhat from the previously-discussed table, because they were derived from slightly different datasets and have slightly different terminology. However, they provide an indication of where future U.S. oil may come from.

III.D.3. Oil Recovery using CO_2

The potential for enhanced oil recovery in the U.S. is increasing continuously with advances in technology. Reservoir modeling, especially for CO_2-EOR, has become extremely sophisticated with the increased capabilities of modern computers and with the development of advanced computer codes that are better capable of mimicking the physics and chemistry of enhanced oil recovery. Improved drilling and completion techniques are also contributing, providing better drilling efficiency and improved well control. New sensing devices and communication systems provide capability for real time analysis of field operations, including underground flow tracking and simulation, thus enhancing the ability to make intelligent decisions in a timely manner. The synergism of the advanced technologies allow a far better understanding and control of oil reservoirs, reservoir fluids, and the physics and chemistry of enhanced recovery.

In addition to advanced technologies, the U.S. also possesses large oil resources. While "proved" reserves struggle to keep up with an ever-increasing appetite for oil, the potential for enhanced recovery is very large -- Table III-6 illustrates the vast resources of oil in the U.S. and the potential for application of advanced technologies to recover some of it. CO_2-EOR will play a significant role in future U.S. oil recovery.

CO_2-EOR is the "universal" enhanced recovery system, applicable to most reservoirs except the very shallow and the reservoirs with heavier oils, for which thermal technologies are more applicable. DOE recently sponsored a 10-basin study to determine the CO_2-EOR potential for the reservoirs in 10 major U.S. basins (and essentially for the U.S., since those basins hold the preponderance of U.S. oil resources). The results of the study are impressive, indicating that as much as 89 billion bbls of oil could be produced by applying modern and forthcoming advanced CO_2-EOR technologies. These estimates are based on assumptions that require the application of the very best technologies available, something that is not likely to happen in every case. Even so, the remaining resources offer a large target for CO_2-EOR, and even if only a portion of the 89 billion bbl estimate can be recovered, it is very much worth pursuing. Table III-7 shows the breakdown by basin of the estimated CO_2-EOR technically recoverable resources in the 10-basin study area.

With more than three decades of experience with the process, companies are becoming more comfortable with using CO_2-EOR. Figure III-12 shows the average oil production per project and reveals that the project size in terms of production has remained stable for the past 14 years, averaging just under 3,000 bbls/day per project. Figure III-13 shows the growth in the number of CO_2 projects over the last 20 years, and Figure III-14 shows the growth in CO_2-enhanced oil production over the same time period. Clearly, the growth in oil production over that time has been directly related to the number of projects being activated. If the price of oil remains high, there should be considerable incentive for companies to initiate new EOR projects, even though past experience has made investors leery of commitments to major projects.

The following excerpts from a recent National Coal Council's report are related to Tables III-7 and III-8, and to this report section in general.

Recognizing the value of this resource [CO_2 EOR], the U.S. Department of Energy Office of Fossil Energy has supported important research on the topic by Advanced Resources International (ARI). The ARI studies demonstrate that one of the most promising modes of recovering remaining oil is by flooding the reservoir with large volumes of carbon dioxide, a process called Enhanced Oil Recovery (EOR). ARI found that EOR has the potential to recover up to 89 billion barrels of oil in ten geographic regions that have historically produced oil: Alaska, California, the Gulf Coast, Mid-Continent (Oklahoma, Kansas), North Central (Illinois), Permian (Texas, New Mexico), the Rockies, Texas East/Central, Williston, and the Louisiana Offshore Shelf. Their study examined 1,581 large reservoirs and found that 1,035 are favorable for CO_2-EOR. The recovery assumes state-of-the-art technology together with improved financial conditions (sustained high oil prices). The ultimate size of the "prize" is 88 billion to 129 billion barrels which are technically recoverable, but which would require next generation technology to get full extraction.

Table III-7
CO_2-EOR Technically Recoverable Resource Potential

Basin/Area	No. Large Reservoirs Assessed	All Reservoirs (Ten Basins/Areas Assessed)		
		OOIP* (Billion Barrels)	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
Alaska	34	67.3	45.0	12.4
California	172	83.3	57.3	5.2
Gulf Coast	239	44.4	27.5	6.9
Mid-Continent	222	89.6	65.6	11.8
Illinois and Michigan	154	17.8	11.5	1.5
Permian	207	95.4	61.7	20.8
Rocky Mountains	162	33.6	22.6	4.2
Texas: East and Central	199	109.0	73.6	17.3
Williston	93	13.2	9.4	2.7
Louisiana Offshore	99	28.1	15.7	5.9
Total	1,581	581.7	390.0	88.7

* Original oil in place, in all reservoirs in basins/areas.
** Remaining oil in place, in all reservoirs in basins/areas.

Source: USDOE Project Fact Sheet, "Basin-Oriented Strategies For Increasing Domestic Oil Production."

> *While EOR activities produced more than 200,000 barrels per day in 2004, it is clear that the potential is far greater. Until recently, the key limitations on expanded use of EOR have been the cost of CO_2 and the limited availability of CO_2 for use in the process. Increasingly, however, it is recognized that CO_2 from coal-fueled power plants is a largely untapped resource, whose use would simultaneously reduce greenhouse emissions and enable the recovery of significant amounts of stranded oil. In addition, the CO_2 resulting from the fermentation of corn during the production of ethanol is also an available source for enhanced recovery. The general underground injection process is also applicable to coalbed methane recovery.*[1]

There are currently limited sources of low cost CO_2 and delivery infrastructure (pipelines) to supply CO_2 to the many oil fields in the U.S. with EOR potential. Coal-to-liquids and other alternative liquid transportation fuels production facilities featured in

[1]National Coal Council, *Coal: America's Energy Future*, Washington, D.C., March 2006, p. 87.

the current study are believed to be a key to unlocking the huge potential of U.S. EOR resources. These plants will be distributed across the U.S., with many sited proximate to EOR-suited oil fields. CO_2 will be a residual product of alternative liquid fuel plants, and capturing the gas for sale will not only create economic value but will also demonstrate environmental stewardship. Thus, it is anticipated that these new liquid fuels manufacturing plants will be a source of low cost CO_2 for EOR operations.

Figure III-11 shows the limited, existing CO_2 sources and pipelines currently delivering this strategic EOR gas to only several regions of U.S. oil fields. Even in these regions, low cost CO_2 is in short supply. Note that many of the basins showing large EOR potential (Table III-7) have no existing supplies of CO_2.

Figure III-11: Existing U.S. CO_2 Sources and Pipelines

Source: CO2 Norway Web Site -- www.co2.no

Additional excerpts from the National Coal Council's report provide further perspective:

> *In the Permian Basin alone, it has been estimated that there could be 50 potentially economical CO_2 floodable reservoirs, representing incremental oil reserves of well over 1 billion barrels. This includes current oil fields that are utilizing water floods, which could become CO_2 floods in the future. However, the problem is that CO_2 is in somewhat short supply, so consideration to use CO2 recovered from power plants for injection is now becoming an issue of growing interest.*

In addition to the Permian Basin, there are other CO_2-EOR projects. Of particular interest is the Dakota Gasification Company lignite gasification plant in Beulah, North Dakota. Originally built during the 1970s energy crisis to produce substitute NG from lignite reserves, it uses Lurgi gasification technology, the same technology utilized by SASOL in South Africa to produce zero sulfur diesel, naphtha and chemicals. The Great Plains Synfuels Plant has the distinction of being the world's first large-scale coal gasification project to substitute NG and the first where CO_2 from coal gasification is removed and utilized specifically for a CO_2-EOR flood. The plant began operating in 1984 and today produces more than 54 billion standard cubic feet of NG annually. Coal consumption exceeds 6 million tons each year, and a number of other products are also produced including ammonia fertilizers, phenol and naphtha.

A portion of the CO_2 produced by this plant (95 mmscfd) is compressed and sent through a 204-mile pipeline through North Dakota to the Weyburn oil field operated by EnCana Corporation in Saskatchewan, Canada. Injection began in September 2000, and the field recently passed a milestone of injecting 5 million tons of CO_2 while doubling the field's production rate to 20,000 bbl/d. The CO_2 from the Dakota plant had been vented for many years.

Thus, a waste product became a source of income for the project, and a source of high-purity CO2 for extended field life (20 years), oil production and revenue from the field. EnCana plans to produce an additional 130 million barrels of oil and sequester as much as 30 million tons of CO_2.

Andarko Petroleum Corporation has extended an existing CO_2 pipeline 125 miles to supply CO_2 to the existing 100-year-old Salt Creek oil field near Casper, from the LaBarge Natural Gas processing plant operated by ExxonMobil in western Wyoming. LaBarge also supplies CO_2 to several injection projects, including the Rangley field in Rio Blanco County, Colorado.

Salt Creek oil production is anticipated to increase from 5,000 bbl/d to perhaps 30,000 bbl/d, with an anticipated CO_2 sequestering of about 25 million tons. Andarko hopes to extract 115 million barrels of oil over 30 years. The Wyoming State Geological Survey recently estimated that there are about 50 oil fields from which perhaps an additional 1.2 billion barrels could be produced using CO_2 injection.

Denbury owns CO_2 reserves in the Jackson Dome and a pipeline in Mississippi, and plans to extend that pipeline into eastern Mississippi and southern Louisiana. EOR production is expected to reach 10,000 bbl/d in 2005 to 33,000 bbl/d in 2010. In Oklahoma, about 9,000 bbl/d of CO2 EOR is produced, using CO_2 from existing ammonia plants.[1]

[1]Ibid., pp. 90-91.

The following figures highlight the current state of CO_2 EOR in the United States. Most of U.S. EOR production comes from the Permian Basin in West Texas and Eastern New Mexico.

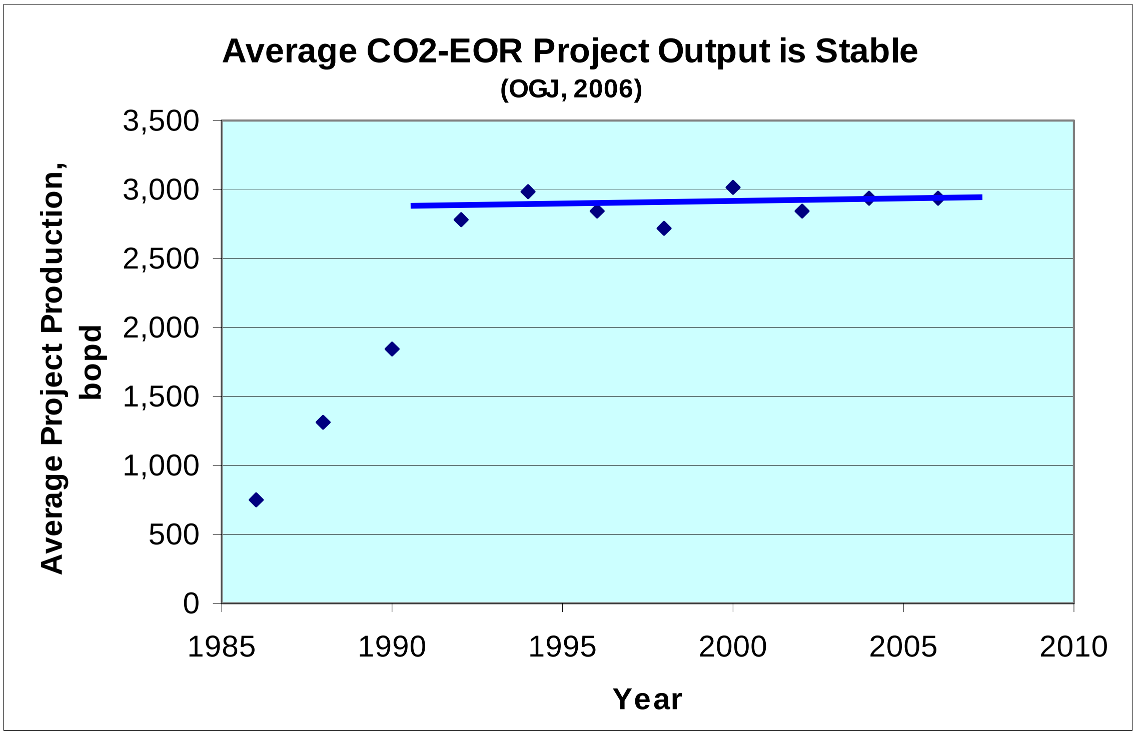


Figure III-12: Average Daily Oil Production per Project Since 1985. (OGJ, 2006)

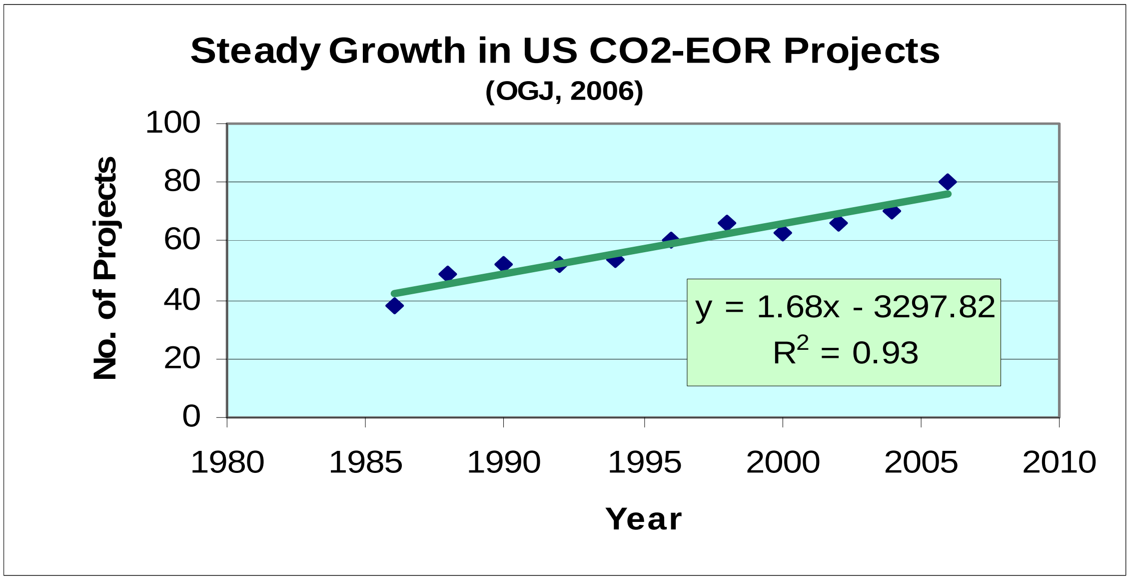


Figure III-13: Steady Growth of CO_2-EOR projects over 20-year Span (Data from Oil & Gas Journal**)**

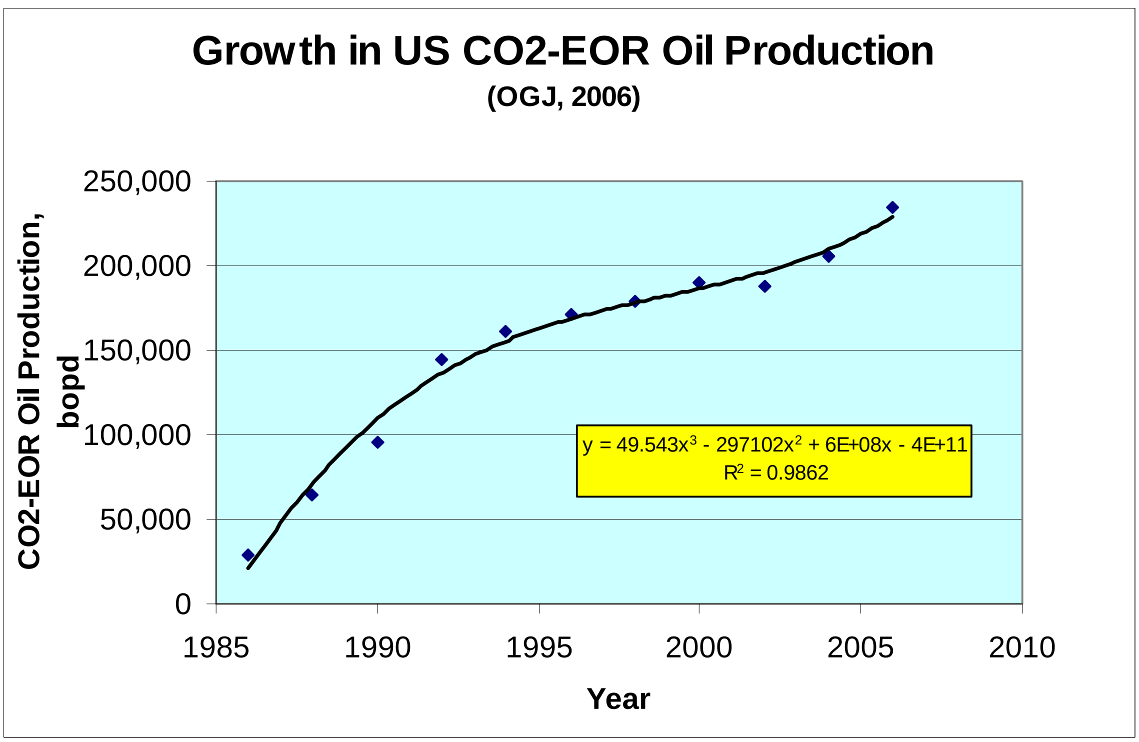
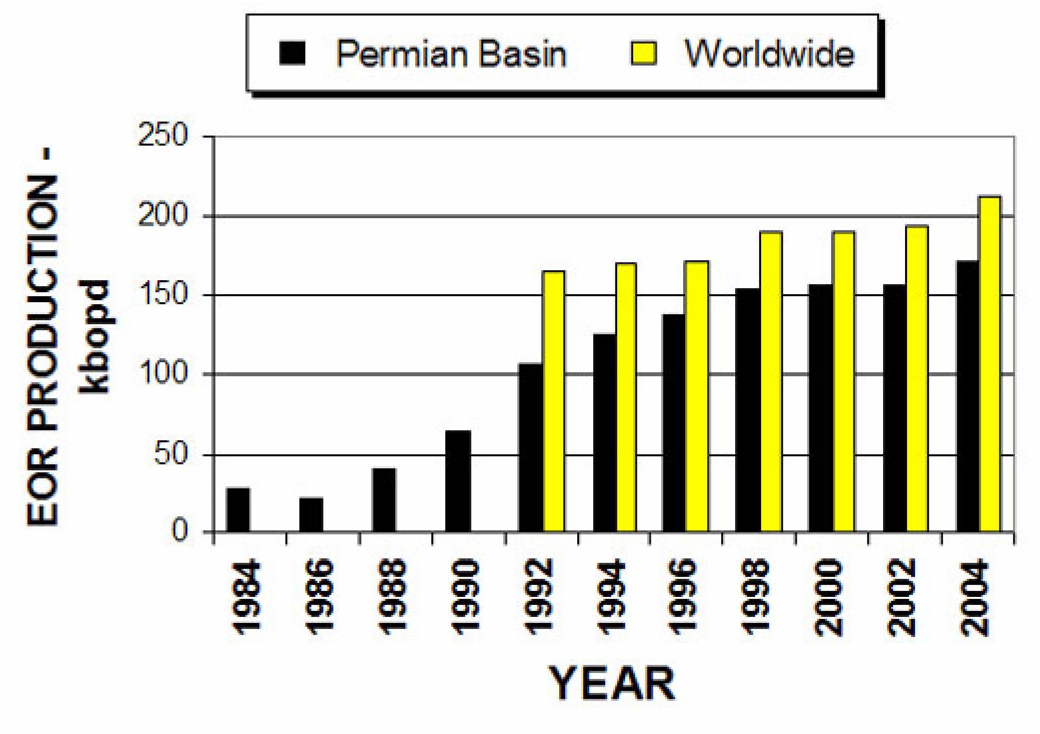


Figure III-14: Growth in US CO_2-EOR Oil Production during Past 20 years (OGJ, 2006)

Figure III-15: EOR Production Worldwide and in the Permian Basin



Source: CO_2 Norway Web Site – www.co2.no

Assuming current shortages of inexpensive CO_2, and a $40/bbl oil price, the expectations for CO_2-EOR are likely to follow or exceed the historical growth pattern, possibly accelerating somewhat as activity picks up in non-traditional areas outside the Permian Basin. Figure III-16 shows the predicted production for CO_2-EOR at $40/bbl with CO_2 supply constraints.

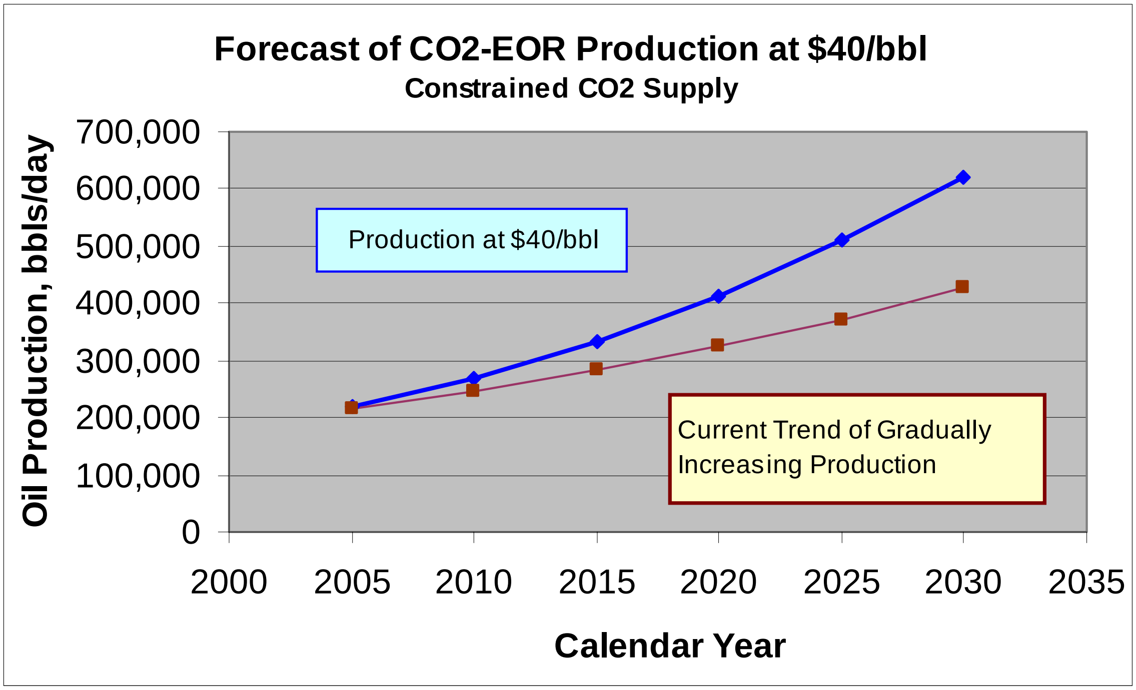


Figure III-16: CO_2-EOR Production Forecast at $40/bbl, Limited CO_2 Supply Scenario

At $60/bbl, assuming that investors will gain confidence that the price will be sustained, additional project starts can be expected, even with CO_2 supply constraints. Previously unplanned projects will likely be fast-tracked into production, but even with that kind of acceleration it will take two to three years to reach maximum production for a project, and only then if a CO_2 pipeline with adequate deliverability is reasonably close by. Figure III-17 shows the projection for oil production based on $60/bbl oil, with limited CO_2 availability.

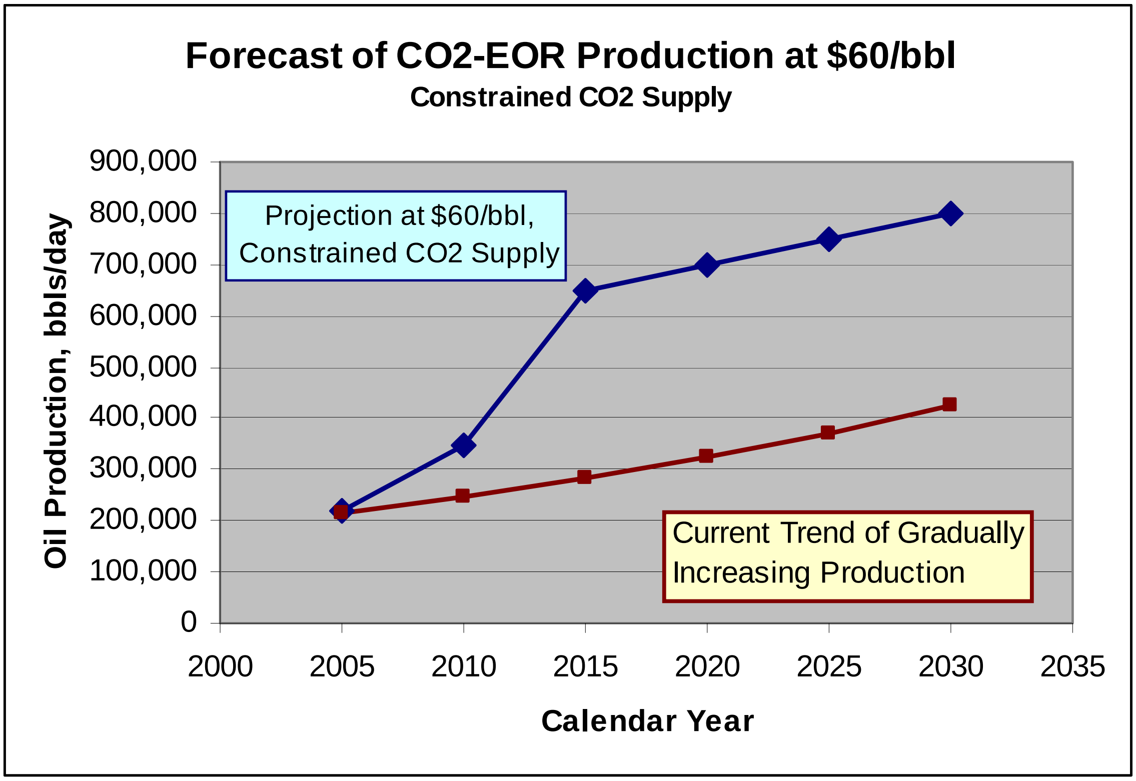


Figure III-17: CO_2-EOR Production Forecast at $60/bbl, Limited CO2 Supply Scenario

III.D.4. Potential for Increasing CO_2-EOR Production by Making More CO_2 Available

CO_2-EOR can provide large additional oil production if CO_2 can be made available near the locations of opportunity, in large volumes, at reasonable cost. If CO_2 can be made available from the manufacture of hydrocarbon liquids from alternative resources such as coal or biomass, then it will be possible to reach many if not most targeted U.S. oil resources, and 2. 0 million bbls/day and more could become a reality.

Development of alternative CO_2 resources needs to be initiated as soon as possible because of the lead time required to develop the CO_2-source coal-to-liquids and other alternative fuel plants and CO_2 transport facilities. Figure III-18 provides one estimate of the potential for CO_2-EOR under an accelerated schedule along with the amount of CO_2 required to achieve it. Under this scenario, there would be approximately 23 billion bbls of oil recovered over the next 50 years requiring about 13 gigatons of CO_2. This projection is probably a reasonable expectation under the assumptions that low cost CO_2 supplies will be available and future oil prices remain high.

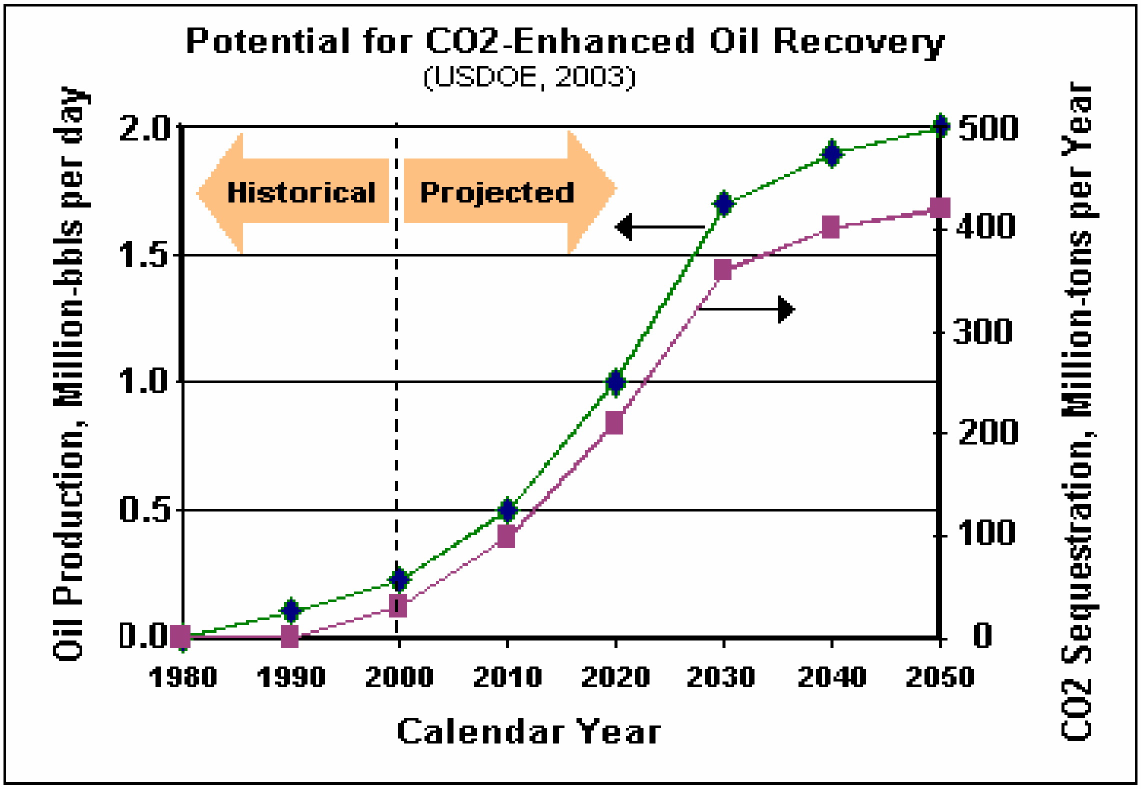


Figure III-18: USDOE Estimate of CO_2-EOR Potential and Associated CO_2 Requirements

Source: USDOE Fact Sheet (No longer available). Also, Kuuskraa, V., ARI, "New Markets for CO2." Second Annual Conference on Carbon Sequestration, **2003.**

In Figure III-18, there are two curves, a green curve to the left with diamond-shaped markers, and a red one to the right with square markers. The green curve shows DOE's (ARI's) projection of possible oil recovery rates in millions of bbls/day (scale is on the left vertical axis) through the year 2050. The red curve shows DOE's (ARI's) projection of the amount of CO2 that will be needed to support those rates of production in millions of tons/year (scale is on the right vertical axis).

The oil production rates in Figure III-18 are shown to increase exponentially through 2020 or 2025, and continue to increase through 2050, but not as rapidly after 2030. This will be the general shape of the curve, since there must eventually be fewer reservoirs available for large-scale enhanced recovery. On the other hand, if the projections for the total amount of oil available for recovery are reasonable and CO_2 supplies remain adequate, which they probably should, the curve might not break over for several years later.

Figure III-19 shows a projection of CO_2-EOR production through 2030 assuming essentially unlimited CO_2 availability and fully favorable economics. Assuming the U.S. decides to launch a concerted effort to achieve energy security and independence, the CO_2-EOR growth shown in Figure III-20 would be possible. The figure depicts about 10 to 11 percent annual growth, which would require coordinated planning and development of CO_2-EOR projects and strategically-located liquid fuels & gasification plants for supplying the necessary CO_2.

The goal is ambitious and will require a lot of things to "go right" over the next two decades: Oil prices will have to remain stable and predictable, and government energy policies will have to help streamline the processes for energy plant siting, permitting, and construction for EOR project development and for environmental protection.

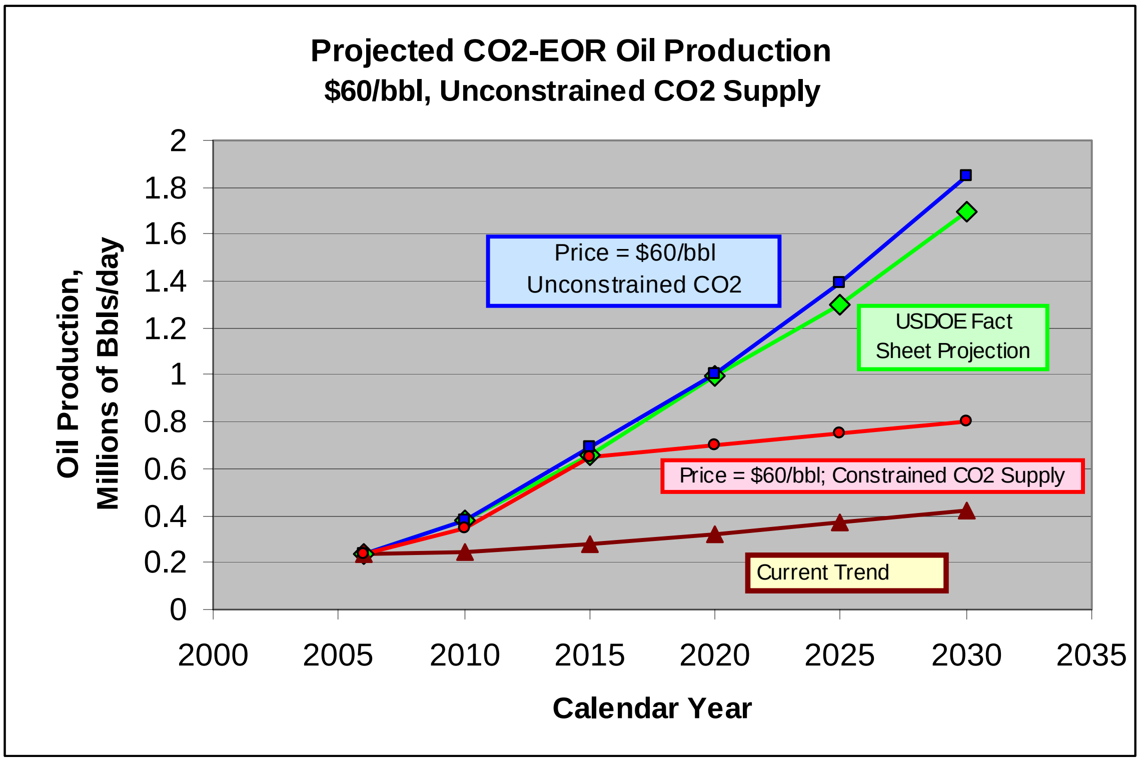


Figure III-19: Projected Potential for CO_2-EOR Production at $60/bbl with Unconstrained CO_2 Availability

Historically, price volatility has been the rule rather than the exception, and risk-aversion has caused energy companies to evaluate all of their large investments very carefully.

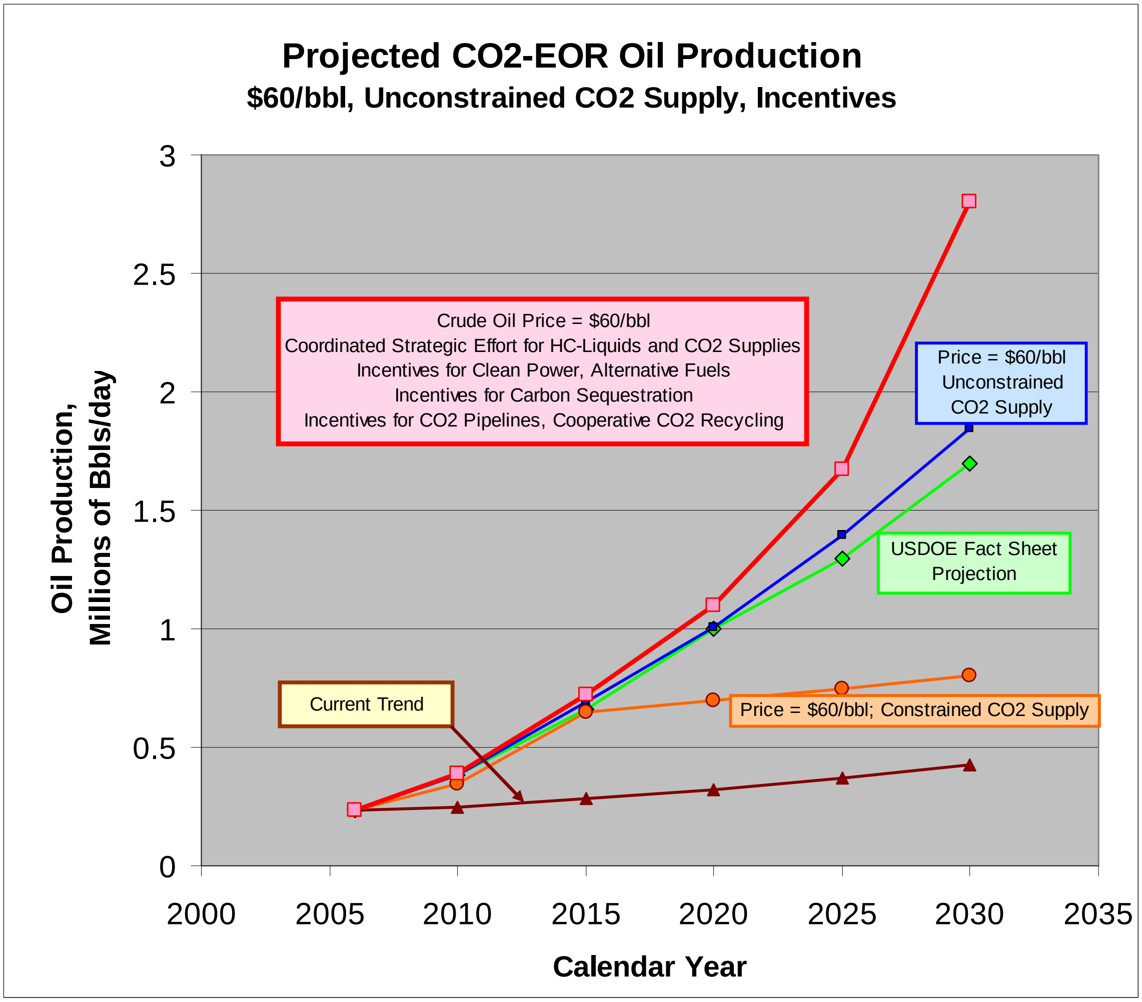


Figure III-20: Projected Potential for CO_2-EOR Production at $60/bbl with Concerted Effort Toward Energy Self-Sufficiency

III.E. Biomass

Biomass comprises the largest single source of renewable carbon on the planet, and starch from corn and other grains is one type of biomass that currently forms the basis for a large and growing renewable fuel industry. The corn to ethanol industry produced more than four billion gallons of alcohol fuel in 2005 and is on track to significantly increase that in 2006. However, use of starch based biomass fuels has an upper limit because of the use of food crops as the starting substrate and the inherent competition with the food markets. The agricultural sector estimated that it can produce between 15 and 17 billion gallons of ethanol from crop-based starches before significant impacts to the food market occur, and to meet the growing demand for liquid fuels it is apparent that lignocellulosic forms of biomass will need to supplant the current starch substrates used for fuel production. Lignocellulosics are what comprise woody types of biomass and include the stalks and leafy material of agricultural biomass, and converting these materials is where the real challenge of biomass to liquid fuel production remains. A recent national study showed that over 95 percent of the biomass resources available on a sustained basis in 2030 would be cellulosic resources.

III.E.1. Biomass Properties

Like coal, lignocellulosic biomass is a complex heterogeneous material and is comprised of carbon, hydrogen, and oxygen having the approximate chemical formula $CH_{1.46}\,O_{0.67}$. On a weight basis it is almost one-third oxygen. The principal components of biomass are cellulose, hemicellulose, and lignin, but volatiles and mineral matter can also be significant in some species. The cellulose and hemicellulose are essentially macropolymeric carbohydrate materials, while the lignin can be considered a complex methoxy phenol macropolymer. The relative proportion of these components, and consequently their molecular makeup, is to a certain degree related to the type of biomass under consideration. The major types are woody and herbaceous species but they also include such categories as algae and animal wastes. The amount of carbohydrates and lignin vary depending on the type of biomass selected for processing. Even within a certain category, such as woody species, there is variability in the chemical makeup of hardwoods versus softwoods. The amount and type of carbohydrates are also significantly different for herbaceous biomass compared to woody biomass. The hemicellulose in agricultural residues is about 32 wt% whereas in hardwoods it is only 23 wt%. The hemicellulose itself is also different, being comprised of arabinose and xylose in the herbaceous biomass but only xylose in the woody biomass. And this only considers the chemical variability.

The physical properties can also vary depending on biomass type, and grasses typically have lower bulk densities than woody biomass. In preparing biomass for feeding into a given process some form of grinding, cutting, or other size reduction is usually required. The resulting prepared biomass feedstock can have different angles of repose depending on how it was processed and on the type of starting material, and designs of feed handling systems must take these variabilities into consideration.

Here we assess the potential for biomass to contribute to liquid fuels production including ethanol, biodiesel, bio-oil, and FT liquids. For purposes of analysis, biomass feedstocks fall into three general resource categories: Cellulosic; starch-based grains; and oils, fats and waste greases (see Figure III-21). Ethanol production from grain and biodiesel production from fats and oils are commercial industries and will continue to make significant contributions to liquid fuels production.[1]

[1]It should be noted that there continues to be debate over the issue of net energy gain or loss with the production of liquid fuels from biomass.

III.E.2. The Existing Industry

The Energy Policy Act of 2005 (EPACT) requires a minimum annual renewable fuels consumption of 6 billion gallons by 2006, and 7.5 billion gallons by 2012. Beyond this, the Biomass R&D Technical Advisory Committee, a panel established by Congress to guide the future of biomass R&D efforts, envisioned that 30 percent of petroleum could be replaced by biofuels by the year 2030 -- "30 by 30;" however, current production levels are only a small fraction of this target.

As of February 2006, U.S. ethanol production capacity was 4.4 billion gallons from 97 ethanol refineries, and planned capacity expansions and new capacity under construction totaled 2.1 billion gallons.[1] Thus, ethanol production will soon exceed the 2006 target of the renewable fuel mandate. Ethanol production consumed 1.6 billion bushels of corn in 2005 (about 14 percent of U.S. corn production), and 2.6 billion bushels of corn are expected to be used by 2010 (about 22 percent of an 11.9 billion bushel crop). Despite the rapid increase in production, ethanol consumption has exceeded production for the past few years, which has led to increased imports. Current production costs for the U.S. ethanol industry average about $1.09 per gallon.[2] Most U.S. production is based on corn, although other feedstocks include wheat, sorghum, and waste beer.[3]

The National Biodiesel Board (NBB) estimates that U.S. production of biodiesel will reach 75 million gallons by 2006, compared to 25 million gallons produced in 2004. There are currently 45 biodiesel plants in the U.S., with an average output of about 6.5 million gallons per year, although some larger plants in the 30 million gallon range have opened and at least 54 more plants are planned. U.S. on-highway use consumed 37.1 billion gallons of diesel in 2003, and at that level of consumption 2005 biodiesel production represents 0.2 percent of supply.[4] NBB estimates that current U.S. biodiesel manufacturing capacity is 290 million gallons per year, 180 million gallons from dedicated biodiesel plants and 110 million gallons within the oleochemical industry.[5]

The existing biofuels industry thus plays an important role in the production of transportation fuels from renewable resources, and the combined capacities of the U.S ethanol and biodiesel industries are approximately 95 million barrels of oil equivalent (boe) per year. However, in 2004, U.S. petroleum consumption for transportation was approximately 13.86 million barrels per day, or just over 5 billion barrels per year,[6] and

[1] U.S. Department of Agriculture, "Ethanol Reshapes the Corn Market," *Amber Waves,* April 2006, www. ers.usda.gov/AmberWaves/April06/Features/Ethanol.htm.
[2] Center for Agricultural and Rural Development, "Policy and Competitiveness of U.S. and Brazilian Ethanol, *Iowa Ag Review Online*, Spring 2006, Vol. 12, No. 2, http://www.card.iastate.edu/iowa_ag_ review/spring_06/article3.aspx.
[3] About 147,000 jobs are supported by the U.S. ethanol industry; see U.S. Department of Energy, *Multi-year Program Plan: 2007-2012,* August 31, 2005. Page 1-7.
[4] Green Car Congress, *U.S Biodiesel Production Triples, Still a Fraction of Overall Consumption,* November 16, 2005.
[5] National Biodiesel Board, *U.S Biodiesel Production Capacity*, September 2005.
[6] U.S. Energy Information Administration, *Basic Petroleum Statistics*, April 2006.

the current biofuels industry thus provides less than two percent of U.S. annual consumption for transportation, or about one percent of total petroleum consumption.

To evaluate the goal of "30 by 30," it is useful to determine the target for biomass in terms of barrels of oil equivalent. Looking just at transportation fuels, the EIA 2006 *Annual Energy Outlook* reference case projects that consumption of motor gasoline, distillate fuel, and jet fuel will total 20.9 million barrels per day in 2030.[1] Thirty percent of this estimate is 2.3 billion boe/yr., or 24 times more than current biofuels production capacity. Clearly there are challenges with achieving this goal and the grain and oil-seed based biofuels industries will not be able to reach this target alone, and there is significant R&D effort being devoted to the development of new technologies which can convert cellulosic biomass to liquid fuels.

III.E.3. U.S Biomass Feedstock Production

Depending upon site specific conditions, one of many technology platforms will be utilized for conversion of cellulosic biomass feedstocks -- the specific technology platforms for converting cellulosic biomass to liquid fuels are discussed in Section IV.E. In April 2005, Oak Ridge National Laboratory (ORNL) completed a major assessment of biomass for the U.S. Department of Energy and the U.S. Department of Agriculture.[2] ORNL sought to determine how large a role biomass could play in addressing the nation's need to reduce oil imports, and whether the biomass resource potential would be sufficiently large to justify the necessary capital expenditures in the fuels and automobile sectors. The ultimate purpose of the ORNL report was to determine whether the U.S. is capable of producing a sustainable supply of biomass feedstocks that could be used to displace 30 percent of petroleum consumption.

[1]Energy Information Administration, *Annual Energy Outlook 2006 with Projections to 2030*, Figure 91, February 2006.
[2]Oak Ridge National Laboratory, *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion Ton Supply*, prepared under contract to the U.S. Department of Energy and the U.S Department of Agriculture, 2005. This report serves as the basis for the current section.

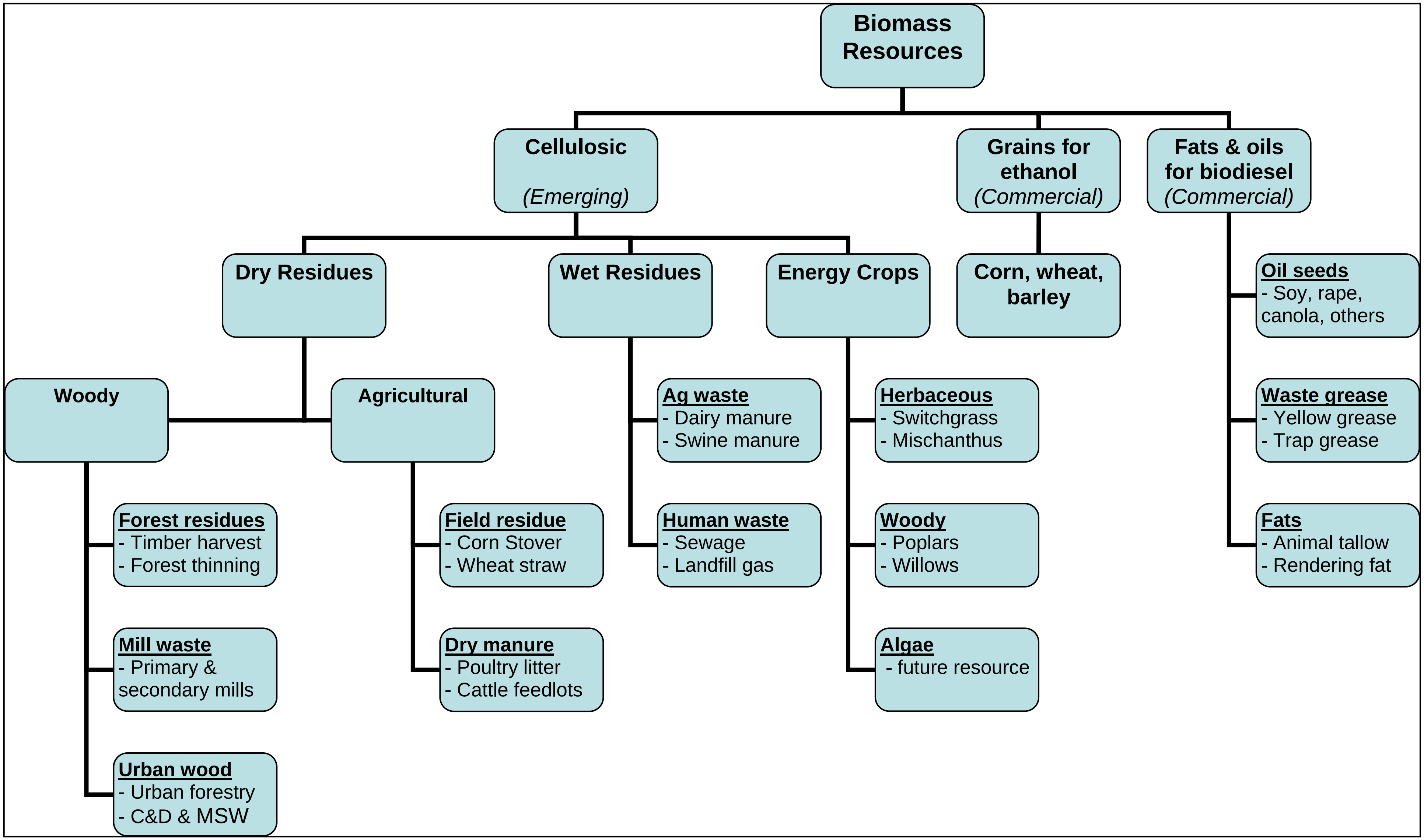


Figure III-21: Summary of Common Biomass Feedstocks

*C&D: Construction and Demolition; **MSW: Municipal Solid Waste

ORNL projected that by 2030 the U.S. could sustainably produce over 1.3 billion tons of biomass per year, measured on a bone dry ton (bdt) basis (Figure III-22), and this would be sufficient feedstock to produce about 1/3 of U.S transportation fuels. The total resource potential is based on an increase of over seven times current biomass production levels. However, the authors believe that the 1.3 billion tons can be produced with relatively modest changes to land use and agricultural and forestry practices.[1]

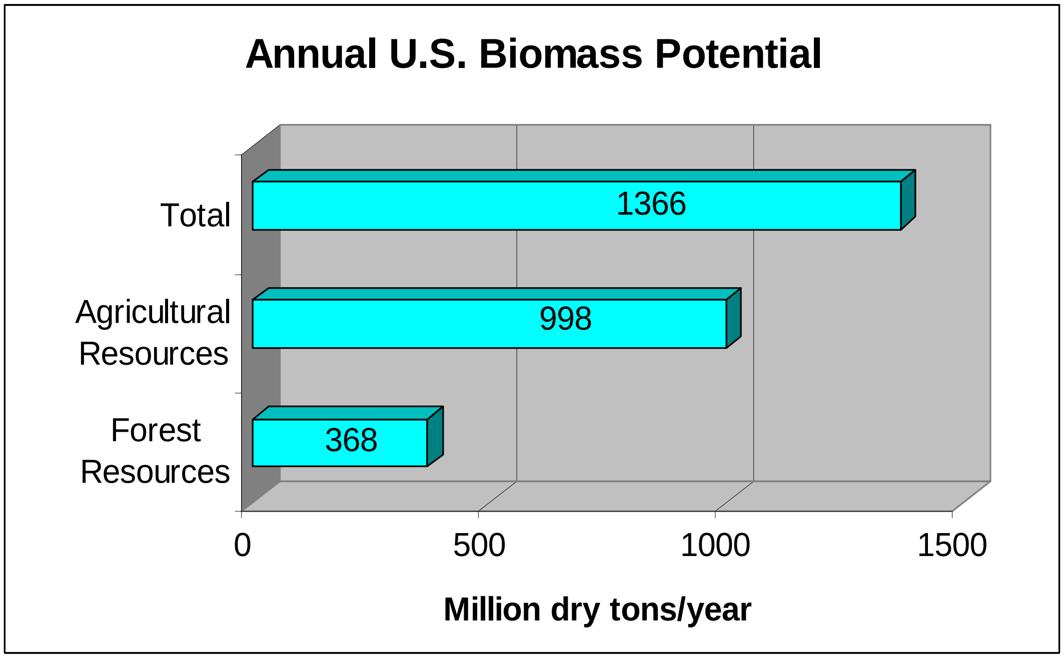


Figure III-22: U.S. Biomass Potential (Source: ORNL, 2005)

Table III-8 shows the breakdown of potential biomass coming from forestlands. ORNL makes several important assumptions, including that all forestlands not presently accessible by roads are excluded, all environmentally sensitive areas are excluded, equipment limitations are considered, and, recoverabale biomass is allocated to both conventional forest products industries and bioenergy and biobased products.

Table III-9. shows the breakdown of potential biomass coming from the agricultural sector. In deriving these data, ORNL makes several important assumptions, including: Yields of corn, wheat, and grain are increased by 50 percent; the residue to grain ratio for soybeans is increased to 2.1; harvest equipment can recover 75 percent of all crop residues; all cropland is managed with no-till methods; 55 million acres of land is devoted to production of energy crops; all manure in excess of that which is applied to land is used for biofuel; and all other available residues are utilized. The

[1]The values in the report should not be thought of as upper limits, but just one scenario for a set of assumptions. Over the coming years, significant additional research will be undertaken.

largest contributing source is estimated to be residues from annual crop production (e.g. wheat straw and corn stover), followed by production of perennial energy crops.

Table III-8
Projection of Biomass from U.S. Forestlands for Bioenergy Production

Resource	Representative Moisture Content	BTU as Received (Btu/lb)	BTU (dry basis, Btu/lb)	Quantity (million bdt/yr)*
Urban wood wastes including construction and demolition	10%-50%	4,000 -8,000	7,600 - 9,600	47
Fuelwood harvest from forest lands	40%-60%	4,000 - 6,400	7,600 - 9,600	52
Undergrowth removal for fire protection	40%-60%			60
Logging and land clearing	40%-60%	~ 4500	7,600 - 9,600	64
Mill residues including pulp and paper	10% - >50%	4,500 - 8,000	8,000 - 9,600	145
Total				368

*bdt: Billions of dry tons.

Source: Osamu Kitani and Carl W. Hall, editors, *Biomass Handbook*, Gordon and Breech Science Publishers, 1989.

Table III-9
Projection of Biomass from U.S. Agricultural Lands for Bioenergy Production

Resource	Representative Moisture Content	BTU as Received (Btu/lb)	BTU (dry basis, Btu/lb)	Quantity (million bdt/yr)
Grains for biofuels	25%-30%	4,300 - 7,300	6,500 - 9,500	87
Animal manure, process residues and miscellaneous	85%	1,000 - 4,000	4,000 - 8,500	106
Perennial energy crops	40%-60%	4,500 - 6,500	6,500 - 9,500	377
Annual crop residues	10%-60%	4,500 - 6,500	6,500 - 9,500	428
Total				998

Source: Osamu Kitani and Carl W. Hall, editors, *Biomass Handbook*, Gordon and Breech Science Publishers, 1989, and Oak Ridge National Laboratory, 2005.

Thus, based on the ORNL analysis, it appears that the potential exists for sufficient biomass resources to be produced for use as feedstock in an integrated biofuels industry.[1]

III.E.4. Cellulosic Biomass Plants – Infrastructure and Scale Issues

Biomass feedstocks are broadly distributed, requiring concentration at a single site, and this makes the development of a biofuels industry both a challenge and an opportunity for nearly every community in the country. As with most industrial processes, large bioenergy plants typically enjoy better process efficiencies and economies of scale when compared to smaller plants. There are many geographic regions of the country where there is a sufficient, reliable supply of biomass to support the development of large scale biofuels plants (1000 bdt/day or larger), along with the associated feedstock collection, transportation, and storage infrastructure. Combination biomass and coal plants offer the potential to increase economies of scale to 10,000 bpd and more, which can lower costs significantly to process biomass into fuels.

The distributed nature of biomass feedstocks means that stand-alone medium-scale bionergy plants will face greater supply risk than smaller plants. Based on the technical and economic challenges associated with moving large quantities of biomass from distances of 50-100 miles, there is considerable opportunity for the development and deployment of small, modular technologies that can efficiently and cost-effectively process on the order of 100-200 bdt/day. In this manner, a network of smaller plants could be deployed in a given region, each utilizing feedstock from a reasonable transportation distance (0-25 miles). These small plants would (1) produce fuels for local distribution and consumption, and (2) through a collection system like that used for smaller oil wells, assemble larger quantities of biofuels for distribution. Due to the distributed nature of a smaller plant system, it would provide enhanced energy security and broad-based economic development.

III.E.5. Biomass Feedstock Costs

It is very difficult to determine the specific cost of biomass feedstocks, as there are significant differences between the various feedstocks, and transportation distance plays a major role in the delivered price of biomass such as forest thinings and agricultural residues. Some biomass is produced on-site as a by-product of other operations (e.g. mill residues), and the costs of these materials are determined by the presence or absence of competing market outlets. If biomass is currently disposed of in landfills, that material may be available free of charge or the processor may even be paid to take it through a tipping fee. Feedstock costs typically range from $0/bone dry ton (bdt) to $50/bdt depending on the resource, the specific location, transportation distance, competing market outlets for the biomass, and the value of the end product

[1]Additional infrastructure will be required to assure adequate consumer access to biomass derived liquid fuels. There is also considerable potential for the use of biomass derived liquid fuels in government vehicle fleets.

being manufactured. Biomass delivered costs also exhibit considerable variability depending on the resource moisture content and energy content in addition to collection and transportation costs. Representative delivered costs by select feedstock categories are given in Table III-10. The range for delivered cost, \$1.36 - \$1.92/MMBtu, is illustrative and can vary considerably from location to location.

Table III-10
Illustrative Delivered Costs for Representative Biomass Resources

Crop	Btu/lb (as delivered)	Moisture Content	$/MMBtu
Wood	4,500	55%	$1.50
Perennial Crops	5,500	50%	$1.36
Corn Stalks	3,900	50%	$1.92

Biomass has potential to be a substantial feedstock for Fischer-Tropsch fuel production. In some areas of the country there is enough waste wood, perrienal crop residue (corn stalks, etc.), animal waste, and other cellulosic resources to be a substantial supplementary feedstock for a large coal-to-liquids plant. In other instances biomass will be the primary feedstock in F-T plants.

III.F. Transportation Energy Efficiency and Conservation

III.F.1. Historical U.S. Oil Consumption Patterns

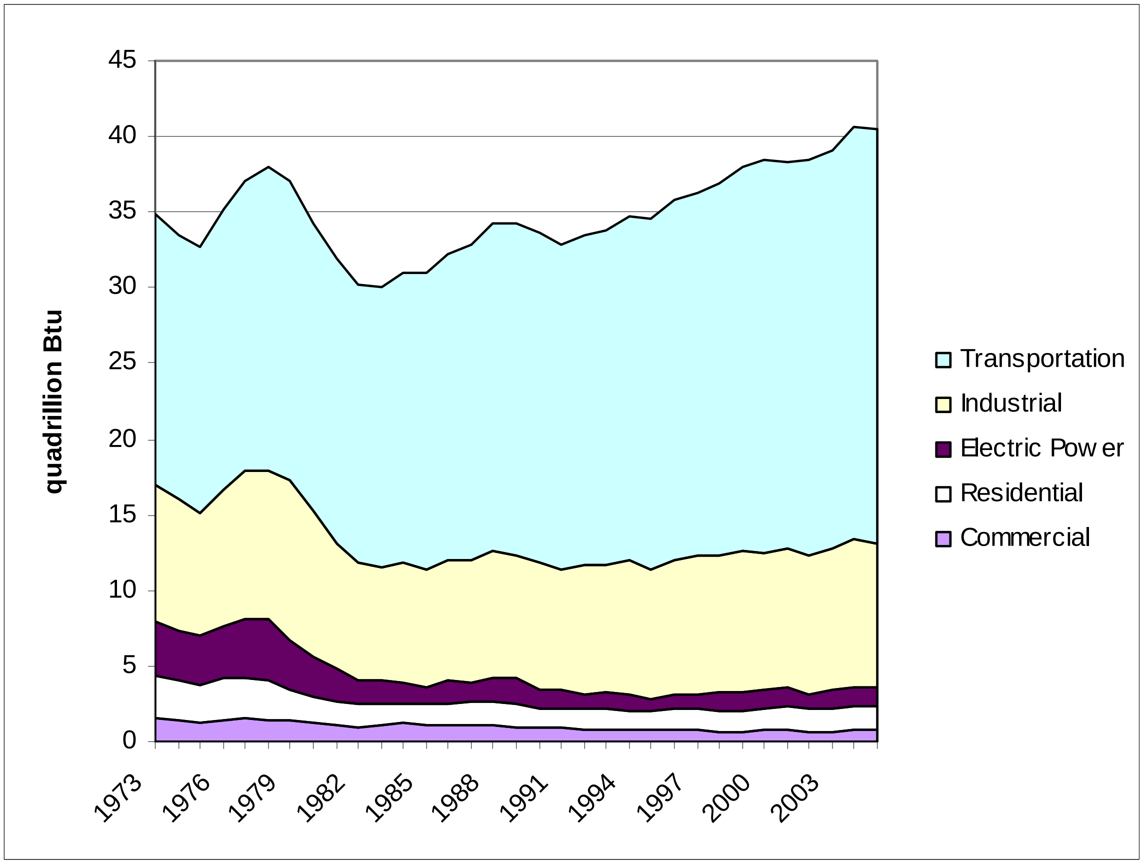
Petroleum use is pervasive throughout the U.S. economy and is directly linked to all market sectors because all depend on oil-consuming capital stock. After the two oil price shocks and supply disruptions in 1973-74 and 1979 oil consumption in the U.S. decreased 13 percent, declining from nearly 35 quads in 1973 to 30 quads in 1983. However, overall consumption continued to grow after the 1983 low and has continuously increased over the last 20 years, reaching over 40 quads in 2004 -- as shown in Figure III-23. In particular, personal transportation grew significantly over the past three decades, and total vehicle miles traveled for cars and light trucks more than doubled over the period.[1] From 1973 to 2005, consumption of oil in the industrial sector stayed relatively flat at just over nine quads, and the industrial sector's share of total U.S. consumption remained between 24 and 26 percent. In sharp contrast to all other sectors, U.S. oil consumption for transportation purposes has increased steadily every year, rising from just over 17 quads in 1973 to 28 quads in 2004. The 40 quad consumption of oil in the U.S. in 2004 is equivalent to over 20 million bpd of oil, including more than 14 MM bpd consumed by the transportation sector. The transportation sector currently accounts for more than two-thirds of the oil consumed in the U.S.

[1] U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics*, 2004.

Automobiles represent the largest single oil-consuming capital stock in the U.S. 130 million autos consume nearly 5 MM bpd, about 25 percent of total consumption -- as shown in Table III-11. Autos remain in the U.S. transportation fleet, or rolling stock, for a long time and, while the financial-based current-cost, average age of autos is only 3.4 years, the average age of the stock is currently nine years. Recent studies show that one half of the1990-model year cars will remain on the road 17 years later in 2007. At normal replacement rates, consumers will spend an estimated $1.4 trillion (2005 dollars) over the next 10-15 years just to replace one-half the stock of automobiles.[1]

A similar situation exists with light trucks (vans, pick-ups, and SUVs), which consume 3.6 MM bpd of oil, accounting for nearly 20 percent of total oil consumption. Light trucks are depreciated on a faster schedule, and their financial-based current-cost average age is 2.9 years. However, the average physical age of the rolling stock is seven years, and the median lifetime of light trucks is 16 years. At current replacement rates, one-half of the 80-million light trucks will be replaced in the next 9-14 years at a cost of over $1 trillion.

Figure III-23
U.S. Petroleum Consumption by Sector, 1973-2005



Source: U.S. Department of Energy, Energy Information Administration, 2006.

[1]This estimate reflects the cost of replacing older, depreciated vehicles with newer, more expensive ones.

Table III-11
U.S. Capital Stock Profiles

	Autos	Light Trucks	Heavy Trucks	Air Carriers
Oil consumption (MM bpd)	4.9	3.6	3.0	1.1
Share of the U.S. total	***25%***	***18%***	***16%***	***6%***
Current cost of net capital stock (billion $)[1]	$571 B	$435 B	$686 B	$110 B
Fleet size[2]	130 MM	80 MM	7 MM	8,500
Number of annual purchases	8.5 MM	8.5 MM	500,000	400
Average age of stock (years)	9	7	9	13
Median lifetime (years)	***17***	***16***	***28***	***22***

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook - 2004*, and Oak Ridge National Laboratory, *Transportation Energy Data Book #23*, 2003.

Seven million heavy trucks (including buses, highway trucks, and off-highway trucks) represent the third largest consumer of oil at 3.0 MM bpd, 16 percent of total consumption. The current-cost average age of heavy trucks is 5.0 years, but the median lifetime of this equipment is 28 years. The disparity in the average age and the median lifetime estimates indicate that a significant number of vehicles are 40-60 years old. At normal replacement rates, one-half of the heavy truck stock will be replaced by businesses in the next 15-20 years at a cost of $1.5 trillion.

The fourth-largest consumer of oil is aircraft, which consume the equivalent of 1.1 MM bpd, representing about six percent of U.S. consumption. The 8,500 aircraft have a current-cost average age of 9.1 years, and a median lifetime of 22 years. Airline deregulation and the events of September 11, 2001, have had significant effects on the industry, its ownership, and recent business decisions. At recent rates, airlines will replace one-half of their stock over the next 15-20 years at a cost of $250 billion.

These four capital stock categories cover most transportation modes and represent two thirds of the consumption of oil in the U.S.[3] The three largest categories

---

[1]U.S. Department of Commerce, Bureau of Economic Analysis, *Fixed Asset Tables, 1992-2002*. The estimate of net stock includes an adjustment for depreciation, defined as the decline in value of the stock of assets due to wear and tear, obsolescence, accidental damage, and aging. For most types of assets, estimates of depreciation are based on a geometric decline in value.
[2]Oak Ridge National Laboratory, *Transportation Energy Data Book #23*, 2003t; and U.S. Department of Transportation, Bureau of Transportation Statistics, *Active Air Carrier Fleet*, 2004,; and Management Information Services, Inc.
[3]The largest remaining oil-consuming capital stock resides in the industrial sector. Oil consumption in the industrial sector is diverse, making it difficult to target specific capital stock and identify potential efficiency efforts or potential technology advancements. The largest oil-consuming industries include the chemical, lumber and wood, paper products, and petroleum industry itself. Functional usage of oil in the industry

of autos, light trucks, and heavy trucks all utilize the internal combustion engine, whether gasoline- or diesel-burning. Clearly, advancements in energy efficiency and replacement in this capital stock (for instance, electric-hybrid engines) would help mitigate the economic impacts of rising oil prices caused by world oil peaking and other factors. However, as described, the normal replacement rates of this equipment will require at least 10-20 years and cost trillions of dollars. Replacement more quickly than within the normal lifecycle would cost consumers trillions of dollars and is not a practical option.

III.F.2. Liquid Fuel Consumption Forecasts and Resource Potential

Table III-12 shows the EIA projection of U.S. liquid fuel consumption through 2030. It indicates that total petroleum demand will increase 33 percent, from about 21 MM bpd in 2004 to nearly 28 MM bpd in 2030: The demand for jet fuel will increase 44 percent, the demand for distillate fuels will increase 33 percent, and the demand for gasoline will increase 31 percent. This indicates that the transportation energy efficiency and conservation resource potential is substantial, and even relatively minor annual increases in transportation fuel efficiency over the next two decades (over and above those assumed in the base case) could result in large liquid fuel savings by 2030. For example, if the motor vehicle and aircraft fleets were only five percent more efficient in 2030 than shown in Table III-13, liquid fuel savings in that year would total 0.75 MM bpd, and if they were ten percent more efficient, liquid fuel savings in that year would total 1.5 MM bpd.

DOE and the Department of Transportation divide the transportation sector into two main categories: "Highway Use" and Non-highway Use." Highway Users include automobiles, motorcycles, 2-axle 4-tire trucks, other single unit trucks, and combination trucks and buses; the Non-highway Use category, which in 2003 used 18.1 percent of the transportation sector energy, includes domestic and international air carriers, general aviation, recreational boating, Amtrak, commuter rail, transit rail, domestic water-borne commerce, pipelines, and Class I rail freight.[1]

At present, the approximate percent of the total energy used for transportation is:

- Automobiles (SUVs, non-business pickup trucks, vans): 59 percent
- Commercial trucking (interstate-hauling/local): 18 percent
- Aircraft (passenger and freight): Nine percent
- Agriculture/construction: Four percent
- Trains and buses (passenger and freight): Three percent
- Marine (passenger/freight), river, lake, coastal: Three percent
- Pipelines: Three percent

---

includes heat, process heat, power, feedstock, and lubrication. Finally, the equipment spans hundreds of disparate types of in situ engines, turbines, and agricultural, construction, and mining machinery.

[1]The DOE/DOT literature does not directly address DOD needs, which includes ground, sea, and air applications, and information regarding agricultural, construction, and postal service applications is limited.

- Military (ground, air, sea): Two percent
- U.S. Postal Service: One percent

Table III-12
EIA Projections of U.S. Liquid Fuels Consumption Through 2030

	2004	2015	2030
Petrolelum Used in MM bpd	20.76	23.53	27.57
Used for Gasoline	9.6	10.63	12.59
Used for Jet Fuel	1.63	2.06	2.31
Distillate Fuels	4.06	4.91	6.06
MM bpd			
Automobile	12.2	13.9	16.3
Commercial Trucking	3.7	4.2	5
Aircraft	1.9	2.1	2.5
Trains and Buses	0.6	0.7	0.8
Marine	0.6	0.7	0.8
Military	0.4	0.5	0.6
Agriculture/Construction	0.8	0.9	1.1
Pipeline	0.6	0.7	0.8
US Postal Service	0.2	0.2	0.3

Source: U.S. Energy Information Administration, 2006.

Thus, the greatest opportunities, by far, for liquid fuel energy efficiency and conservation savings are in the automobile fleet, including SUVs, non-business pickup trucks and vans. In fact, this sector uses nearly 60 percent of all transportation energy, and this is the reason why transportation fuel efficiency programs have historically been targeted to this sector. The next largest opportunity for liquid fuel savings is in the commercial trucking sector, which uses about 18 percent of transportation energy. However, not only does this sector use less than one third of the amount of liquid fuels as the automotive sector, but the technical opportunities for fuel efficiency savings are also more limited. Aircraft use about one-seventh as much liquid fuel as the automotive sector and half as much as commercial trucking. The quantitative impact of fuel efficiency savings in this sector, while important, will be much less in total than the automotive or trucking sectors. Finally, the amounts of liquid fuels used in the other sectors are, in comparison, small and the likely efficiency savings in each of these sectors will be almost miniscule compared to the potential in the first three sectors.

IV. TECHNOLOGY ASSESSMENT

IV.A Overview

A vast array of technologies exist that can produce liquid fuels from coal, oil shale, and biomass resources, that can facilitate enhanced oil recovery from U.S. reservoirs, and that can save millions of barrels per day of liquid fuels in the transportation sector.

Coal Liquefaction

There are two basic technologies for producing liquid fuels from coal: Direct and indirect liquefaction. Direct liquefaction produces a synthetic crude that must then be refined to produce gasoline and diesel fuel, whereas indirect liquefaction involves gasification of coal to produce a syngas that is then converted into liquid fuels via Fischer-Tropsch (FT) synthesis. Indirect liquefaction is a well developed technology and has been used by Sasol (a company in South Africa) to produce liquid fuels from coal for more than five decades. In this study we assume that all of the coal-to-liquid (CTL) plants to be built will utilize indirect liquefaction, which can produce high quality liquid fuels, such as diesel and jet fuel, that can supplement or substitute for the fuels now produced from petroleum.

Oil Shale

Oil Shales can be produced by mining (surface or underground) with surface retorting or by in-situ processing. Oil shales for surface retorting can be surface mined or deep-mined, and once the shale has been mined, it is heated to convert – or retort -- the kerogen and create shale oil and combustible gases. Numerous approaches to surface retorting have been tested at pilot and semi-works scales. In-situ processing involves heating the resource in-place, underground, and various approaches have been tested, including true in-situ and modified in-situ. True in-situ processes involve no mining: The shale is fractured, air is injected, the shale is ignited to heat the formation, and shale oil moves through fractures to production wells. Modified in-situ (MIS) involves mining below the target shale before heating and requires fracturing the target deposit above the mined area, and the shale is heated by igniting the top of the target deposit. Here we assume that surface retort and true in-situ technologies will be used.

Enhanced Oil Recovery

The most promising technology for enhanced oil recovery (EOR) involves the injection of CO_2 into the oil reservoir, and the potential for CO_2-EOR in the U.S. is increasing continuously with advances in technology. Reservoir modeling, especially for CO_2-EOR, has become extremely sophisticated with the increased capabilities of modern computers and with the development of advanced computer codes. The synergism of the advanced technologies allow a far better understanding and control of oil reservoirs, reservoir fluids, and the physics and chemistry of enhanced recovery. CO_2-EOR is the "universal" enhanced recovery system, applicable to most reservoirs except the very shallow and the reservoirs with heavier oils, for which thermal technologies are more applicable. DOE estimates that as much as 89 billion bbls of oil could be produced by applying modern and forthcoming advanced CO_2-EOR technologies. With more than three decades of experience with the process, companies are becoming more comfortable using CO_2-EOR.[1]

Biomass

Liquid fuels are complex mixtures of hydrocarbons or oxygenated hydrocarbons in the form of ethers or alcohols. The transformation of biomass into these types of compounds involves breaking down the macropolymers of biomass into elemental molecules and then reconfiguring these molecules into the desired fuel compounds. There are two fundamental approaches to this transformation: One is a bioconversion approach and the other uses thermochemical methods. Commercial ethanol and biodiesel liquid fuels production is well established in the U.S., and new pyrolysis and thermal depolymerization techniques are being developed to produce hydrocarbon fuels from cellulosic resources. Large polygeneration carbon-to-liquids plants can process a varied blend of coal, oil shale, and biomass feedstocks into oil. These combination plants first will gasify the carbon-bearing feedstocks and then combine the product gases into liquid fuels using well established Fisher-Tropsch technology.

Transportation Energy Efficiency and Conservation

The technical options for improving light duty vehicle fuel efficiency can be classified into two basic categories: Powertrain technologies, which include engines, transmissions, and the integrated starter-generator, and load reduction technologies which include mass reduction, streamlining, tire efficiency, and accessory improvements. Many of these technologies are currently under production, product planning, or continued development. In addition, there are a number of other technologies and initiatives that can be used to reduce petroleum demand in the trucking, airline, marine, and rail transportation sectors. In this study we assumed that, coincident with the crash substitute fuels programs, transportation fuel efficiency will also increase substantially by 2030, and the generic gains likely from transportation efficiency and conservation reduce forecast overall U.S. petroleum requirements. Mass transit, rail, and light rail initiatives were also assumed to be part of the transportation energy efficiency program.

[1] Major studies and demonstration projects funded by DOE are currently underway in the area of CO_2 capture and utilization techniques.

IV.B. Coal-to-Liquids

IV.B.1. History of Fischer-Tropsch (FT) synthesis and Sasol

The German and U.S. Experience

The discovery and successful commercialization of ammonia synthesis in Germany during the 1908-1920 period put Germany at the forefront of very high pressure processing. To take advantage of this accomplishment, efforts were made to develop other high pressure processes. Two of these involved the conversion of coal to transportation fuels: Direct coal liquefaction through high temperature and high pressure processing and indirect coal liquefaction through first converting coal to a mixture of hydrogen and carbon monoxide and then converting the mixture to liquid products. This latter approach was discovered by Franz Fischer and Hans Tropsch in the 1920's and is referred to as the Fischer-Tropsch (FT) synthesis. With the approach of WW II, the Germans decided to concentrate on direct coal liquefaction and no commercial FT plants were constructed after 1939.[1]

The Germany industry for FT synthesis utilized cobalt based catalysts, and these were initially operated at atmospheric pressure and then at intermediate pressure (2-30 atm). While the Germans investigated many types of reactors at the laboratory scale, only fixed-bed tubular reactors were utilized commercially. These commercial reactors were sized to produce about 15 barrels of liquid products per day, very small scale reactors by today's standards. To scale up plant production, more of the 15 barrel/day units were constructed; however, because of a limited supply of cobalt, significant work was undertaken during WW II to develop iron catalysts. While the iron catalyst development progressed through pilot plant testing, no commercial operation utilized iron catalysts.

Following WW II, Kölbel and co-workers carried the development work they conducted for Rheinpreussen through to a large pilot plant. This work utilized iron catalysts that by today's classification would be considered a low alpha catalyst producing primarily gaseous and gasoline products. A significant feature of Kölbel's work was the development and utilization at the pilot scale of what is known today as a slurry bubble column reactor. Kölbel and his co-workers developed significant scientific and technical advances in the understanding of the slurry bubble column reactor.

In the late 1940s, a group of companies headed by Hydrocarbon Research Inc., undertook the development of a commercial operation in Texas that would produce about 8,000 bbl/day of hydrocarbon products using FT technology. This operation was based on a conventional fluid bed reactor and was in contrast to the circulating fluid bed reactor that Kellogg developed at about the same time. Because the Texas plant was a

[1]The decision to concentrate on direct coal liquefaction was more a result of politics than of technology, and details of these developments were widely circulated following the end of WW II. See *Report on the Petroleum and Synthetic Oil Industry of Germany*, Ministry of Fuel and Power, His Majesty's Stationery Office, London, 1947.

grass-roots operation, new gasification and new FT processes were utilized. Start-up problems plagued the operation for about three years and just as these problems were being solved, the price of natural gas increased dramatically, resulting in termination of the FT operations. After the energy price increases in the early 1970's there was renewed interest in FT, but much of it focused on converting natural gas to liquids (GTL) rather than coal to liquids (CTL).[1]

The South African Experience[2]

The world's only commercial integrated coal-to-liquid fuels and chemicals are currently produced in South Africa by the Sasol company, and there currently exist two commercial GTL plants -- Shell in Malaysia and PetroSA in South Africa -- a third one is now being commissioned by Sasol in Qatar. The history of Sasol's success stretches back many years and in retrospect it is a development based on astute planning, foresight, willpower, and fortuitous timing. This history is covered briefly, and it provides some lessons for alternate liquid fuel technology commercialization.

A white paper was submitted to the South African Parliament in 1927, indicating the fact that since no oil has been discovered in South Africa, the new German FT invention held promise for South Africa. Dr. Fischer visited South Africa and plans were developed to establish a production facility, and at that time there was no issue of political pressures or limited access to internationally traded oil.

With the advent of the Second World War, these negotiations were interrupted and in 1950 the "South African Coal, Oil and Gas Corporation" was established as a private sector company under government funded sponsorship of the Industrial Development Corporation. A commercial CTL plant was erected on a green field site about 50 miles south of Johannesburg at a place named Sasolburg, and it began producing synfuels in 1955.

The technology developed by the Germans used the "low temperature" FT variant, but developments in the U.S. used the "high temperature" FT. The former produces more paraffinic and waxy products whereas the latter produces a lighter product spectrum including a high olefinic yield. At the time Sasol was built, neither of these technologies was commercially proven, and to reduce risk it was decided to include both the German and the U.S. technology in the Sasolburg plant. Other major first-of-its-kind processes applied at commercial scale included the oxygen plants (at that time the largest in the world), the Lurgi gasifiers, the Rectisol gas purification plant, the Phenosolvan tar work-up plant, and the refineries. After several years of teething troubles and unique technical issues, production stabilized in the early 1960's. At that time it was not considered economic to build more FT plants, and various petrochemical

---

[1]These developments are not covered here except to note that a number of companies have been active internationally in the FT field and have erected various scale pilot and development FT units. These include ExxonMobil, BP, Shell, Statoil, IFP/ENI, PetroSA, Syntroleum, Rentech, and several others. Some of these companies are proposing to commercialize their CTL technologies in the U.S. and elsewhere.
[2]Sasol web site www.sasol.com.

plants and a crude oil refinery (Natref) were built at and around the Sasol plant. This stimulated development of an extensive petrochemical complex producing a range of chemicals such as ethylene, butadiene, styrene, and fertilizers.

The next major phase in Sasol's history came about due to the energy crisis of 1973. When oil prices rose sharply, Sasol proposed to the South African Government to build a much larger facility, Sasol Two, since there was a clear economic justification for this project at prevailing and projected prices. In 1974, approval was given and negotiations with the government through the Industrial Development Corporation included assurances regarding a floor price and loan guarantees. A major thrust was the desire to save foreign exchange associated with oil imports. At that time, the mandatory international sanctions against South Africa were not in place,[1] and it is a common misperception that Sasol Two was built in response to the sanctions. This second facility was located at a green field site at a site called Secunda.

While the Sasol Two project was under way, the Shah of Iran was toppled and the supply of crude oil from Iran, with which the Iranian Oil Company's share in the Natref refinery was covered, was disrupted. A decision was then taken within one month to proceed with a twin plant, called Sasol Three, adjacent to Sasol Two. This was a decision influenced by sanctions; however, it should be noted that throughout the sanctions period South Africa was still able to access crude oil and imported crude that satisfied 60 percent or more of the national fuel needs.

About $500 million was saved on the project by building a twin plant, and the all-inclusive combined project cost for the two plants was about $6 billion. With Fluor as the managing engineering contractor, the projects were completed on budget and on schedule. At that time it was the largest single site construction job in the world and a peak multi-national workforce of about 22,000 people were on site. Sasol Two went into full operation in 1980 and Sasol Three in 1983.

Each plant had a nameplate capacity of 50,000 bbl/d of fuels. At the time of the commissioning of Sasol Three, Sasol provided South Africa with about 40 percent of its domestic transportation fuel as synfuels from coal. Over the years, the net equivalent energy production as fuels rose to about 160,000 bbl/d. In spite of this capacity growth, Sasol currently supplies only about 28 percent of the nation's automotive fuels due to the growth of South African consumption over the years and the fact that more and more components from the fuel streams have been withdrawn for chemical use.[2]

The design philosophy for the Secunda facilities was to use only technologies and processes that had been proven at least at demonstration scale, and this decision was a key element in ensuring the smooth and rapid commissioning of the plants. Delayed commissioning after a capital investment of this magnitude has been made is

[1]The UN resolutions were passed in 1977, and were not always well enforced.
[2]Sasol (which now owns Natref which produces about 120,000 bbl/d) currently supplies about 40 percent of South Africa's fuels if the crude oil derived products from Natref are added to the 28 percent provided by synfuels.

one of the most serious risks factors that can negatively impact the early start to recover the capital investment.

The Secunda plants were using only the high temperature FT synthesis version and the main products were thus gasoline and a range of chemicals which are co-products of the high temperature FT. Diesel was produced both from “straight run” FT products but also from oligomerizing the lighter olefins, and this provided flexibility to meet market demands in terms of the ratio of gasoline to diesel. Over time more chemical plants were added, many of which applied unique Sasol-developed technologies to recover and market high purity chemicals from the product streams.

Debottlenecking continued and additional production capacity was added either to increase the production of certain products, to improve efficiencies, or to improve environmental performance. Sasol stated that already at the design stages of the Secunda facilities (1970s) 15 percent of the total costs were for environmental protection. Over the past decade, extensive environmental improvements have been made, including a catalytic NO_x reduction reactor commissioned at Sasolburg and ongoing improvements in sulfur recovery at Secunda.[1]

Due to the increasing cost of production of coal at Sasolburg and the difficulty of meeting new environmental standards through retrofitting in the more than 50 year old plant, several years ago it was decided to switch the syngas production at Sasolburg to use of a recently developed natural gas supply from Mozambique. The gas pipeline from Mozambique to Sasolburg via Secunda was completed in 2004 and in 2005 the gasifiers at Sasolburg were replaced with autothermal gas reformers producing syngas from natural gas.

When using data from the Sasol facilities (both at Sasolburg and at Secunda) as reference points for CTL plants, a number of factors should be considered:

- At Sasolburg, additional steam was produced and sold to adjacent factories.
- Due to the two dissimilar FT technologies used at Sasolburg, higher capital investments were required because the product work-up facilities were more complex than if only one FT system had been used.
- The Secunda plants have multiple chemical facilities, which impact the site energy and infrastructure parameters. To relate the coal consumption direclty to liquid fuels production only can lead to erroneous conclusions.
- At both sites there were ongoing process optimizations (more than 50 years at Sasolburg and more than 25 years at Secunda) which

[1]Sulfur recovery, which was 70 percent in the 1970’s, is currently more than 96 percent efficient using state-of-the-art technology. If a completely new system were to be designed today, modern permit levels would be achievable.

makes it hard to “untangle” data for individual processes in such highly integrated petrochemical complexes.

- The coal used by Sasol is owned and mined by Sasol. The coals are sub-bituminous with an ash content at Sasolburg of 30-35 percent and at Secunda of 22- 25 percent. In both facilities power is generated for parasitic use.

With respect to the commercialization of Sasol, it should be noted that:

- Although Sasol was started with government funding through the Industrial Development Corporation, it was always managed like a private sector company.
- In 1979 Sasol was listed on the Johannesburg Stock Exchange and the share issue was over-subscribed by a factor of 31, which indicates the very high level of support Sasol enjoyed from investors. Subsequently, as Sasol diversified and entered into international markets, its shares were also listed in overseas markets, such as the NYSE.
- The government provided loan guarantees and a floor price mechanism to Sasol to facilitate the financing of the Sasol Two and Three facilities. South African fuel prices are regulated on an import parity basis. The approach was that if the price was below an agreed level, the government provided support, whereas Sasol repaid the government when prices were above a pre-determined level, until the supported amounts had been redeemed. In due time all government support to Sasol was repaid and the support mechanisms have been terminated.
- The high oil prices in the early 1980’s, as the Secunda plants came into production, enabled Sasol to make rapid payments to reduce the capital debt on the facilities.
- Currently Sasol is the South African company with the highest level of capital reinvestment in South Africa.

There are multiple benefits to South Africa from having established the Sasol facilities, including strategic benefits and the savings of foreign exchange for oil imports. In addition, Sasol became a very large employer: Its worldwide employment currently exceeds 35,000, and this results in significant economic multiplier effects in the manufacturing, maintenance, and services industries. Further, Sasol makes important educational and scientific contributions to South Africa.

Over the years Sasol has continued to invest in ongoing R&D and it currently has the largest R&D team in the chemical/chemical engineering field in South Africa. It has continuously improved its leading position in FT synthesis and has developed two new and more profitable versions of both the high temperature and low temperature FT reactor systems. The former were installed in the Secunda facilities where reactors of this design now produce more than 20,000 bbl/d per single reactor. The latter type is being commissioned in the Oryx gas-to-liquids facility in Qatar, where each of two reactors in the plant will produce 17,000 bbl/d. New Sasol CTL plants will thus be based on improved technologies and the extensive operating experience of more than five decades.

IV.B.2. Coal-to-Liquids Technology

Indirect coal liquefaction is a three-step coal-to-liquids technology: 1. Coal gasification, 2. Fischer-Tropsch (FT) synthesis, and 3. FT product upgrading. Each process is described below.

Gasification

Gasification is a process that, through heat and pressure, can convert coal (or virtually any carbon-containing material) into a gaseous product stream called "syngas." Syngas is made up primarily of hydrogen and carbon monoxide, and can be used in many ways, including the production of Fischer-Tropsch and other fuels, electricity, chemicals, fertilizers, hydrogen, CO_2 for Enhanced Oil Recovery, steam, and as a source of substitute natural gas. In addition to coal, possible feedstocks include petroleum coke and other residue from petroleum processes, biomass, and municipal and industrial waste – see Figure IV-1.

The feedstock enters the gasifier, where it encounters steam and oxygen or air in a condition of high temperature and pressure. These cause the feedstock to be broken down into syngas and a solid ash waste product. The ash is typically removed from the bottom of the gasifier while the syngas enters a purification system. Gas cleaning removes impurities including sulfur, particulates, carbon dioxide (CO_2), and related products, the majority of which are saleable byproducts. Separation units also recover the hydrogen and carbon monoxide syngas.

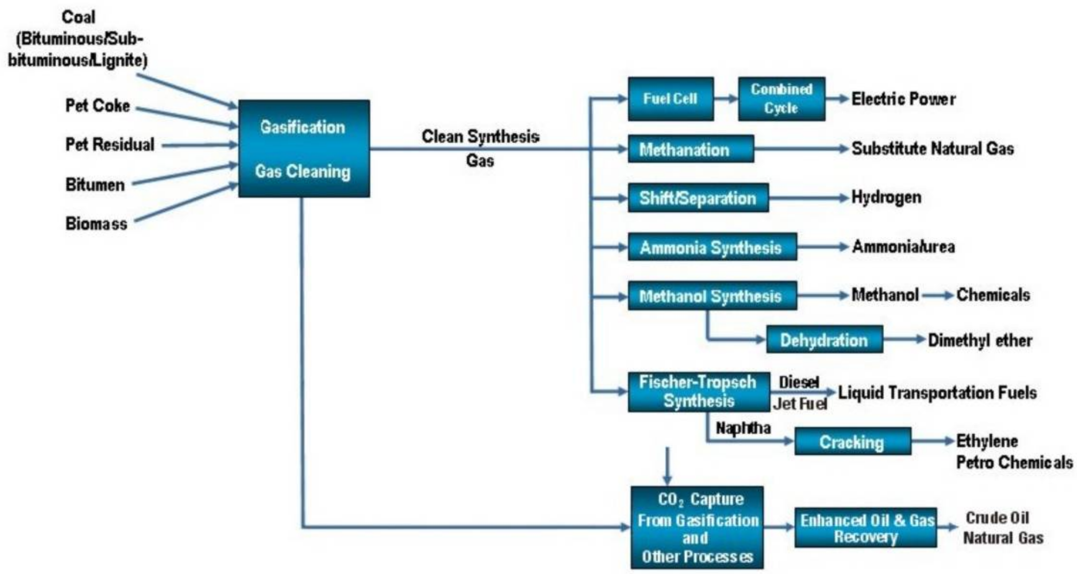
Gasification technologies are believed to represent a next generation of solid-feedstock-based energy production systems. Gasification breaks down virtually any carbon-based feedstock into its basic constituents, and this permits the economic separation of pollutants and CO_2. The process also provides flexibility in the production of a wide range of products, as previously noted. The economics of gasification can be improved by fully utilizing and/or selling all outlet streams of the process, including byproducts from waste streams. Byproducts include pressurized CO_2, ash/slag, sulfur and/or sulfuric acid, hydrogen, and ammonia.

The Department of Energy's National Energy Technology Laboratory (NETL) maintains a world database of gasification plants. According to this database, as of 2004 there were more than 115 gasification plants operating around the world, and about 50 more in development.[1] From NETL's database records it is evident that the

[1]An Excel spreadsheet containing plant-by-plant summary information from the NETL 2004 gasification database can be accessed on the web at www.netl.doe.gov/technologies/coalpower/gasification/database/GASIF2004.xls

primary gasification technology providers are Shell, GE, Lurgi, and ConocoPhillips E-Gas (formerly Global, Destec, Dow). Graphics summarizing pertinent data in the NETL world gasification database are presented in Figures IV-2, IV-3, and IV-4.

Figure IV-1
The Many Products Possible from Gasification



Fischer-Tropsch Synthesis

The Fischer-Tropsch process is named after F. Fischer and H. Tropsch, two German scientists who developed it in 1923. The process is a chemical reaction in which carbon monoxide and hydrogen (synthesis gas) are converted into liquid hydrocarbons of various forms at temperature using a catalyst. The most common catalysts are iron and cobalt.

In an approximate ratio of two hydrogen molecules to one carbon monoxide molecule, the synthesis gas is sent through an FT reactor containing a catalyst where the syngas is converted to a range of hydrocarbon products, particularly naphtha, diesel fuel, jet fuel (kerosene) and wax. The wax can be inexpensively upgraded into additional diesel fuel, jet fuel, naphtha, and other products. FT reactor product yields depend on pressure, temperature, feed gas composition, catalyst type, catalyst composition, and reactor design.

Figure IV-2

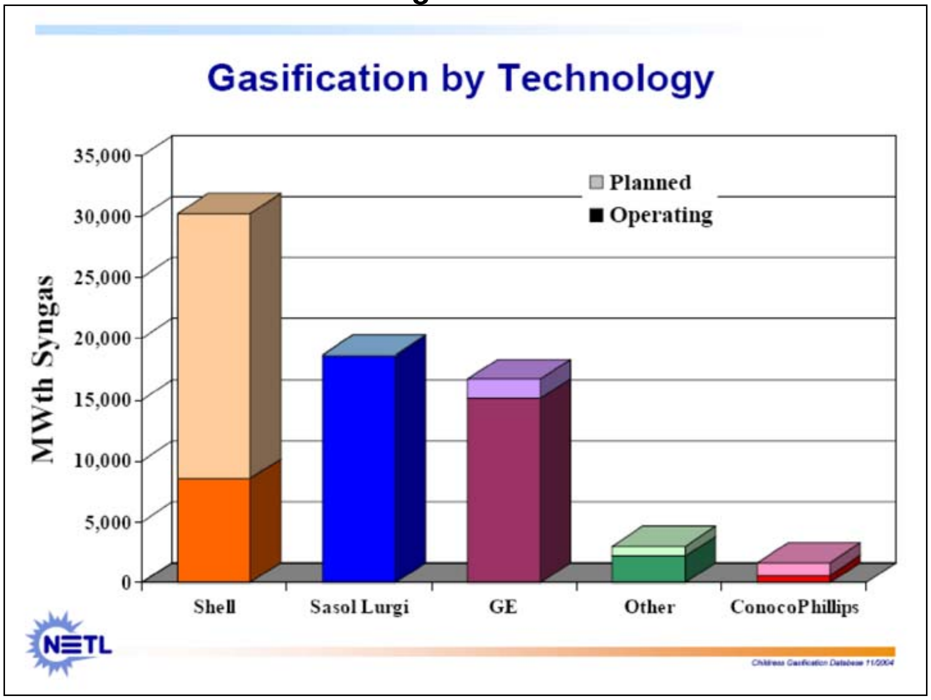


Figure IV-3

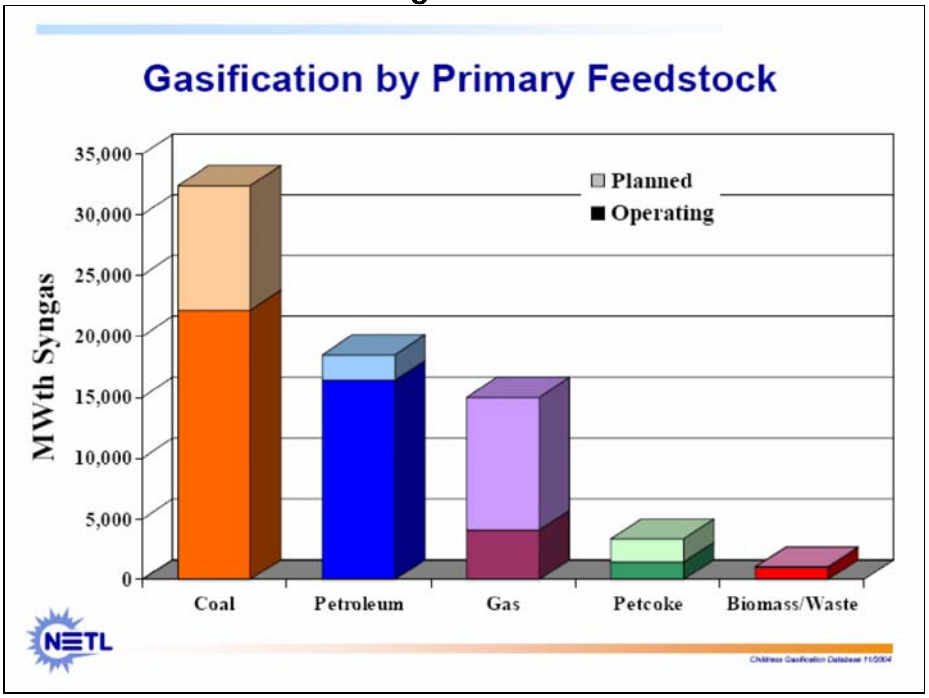
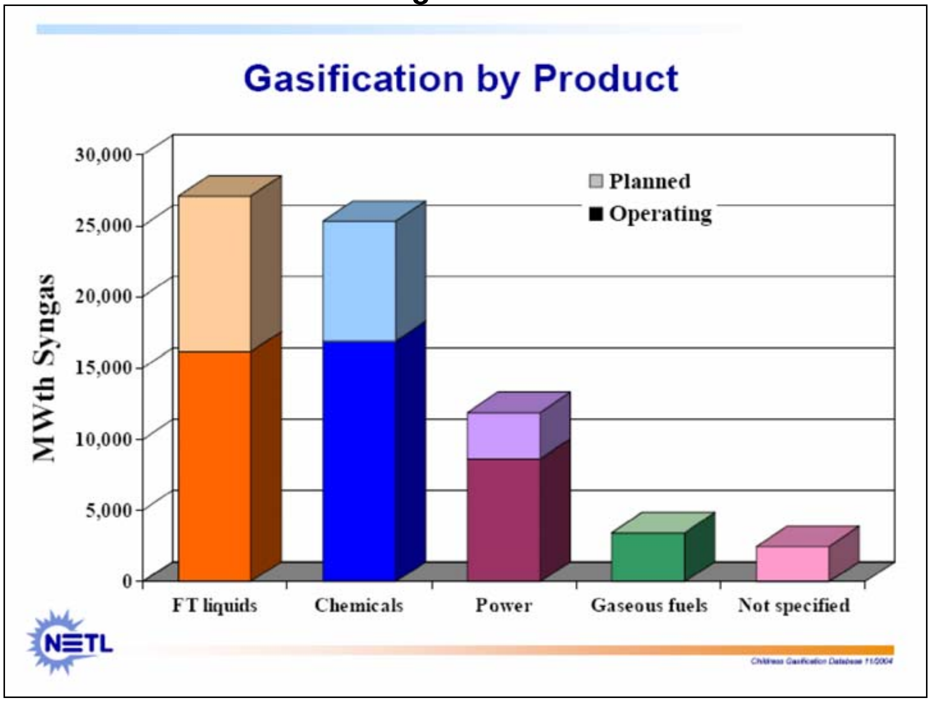


Figure IV-4



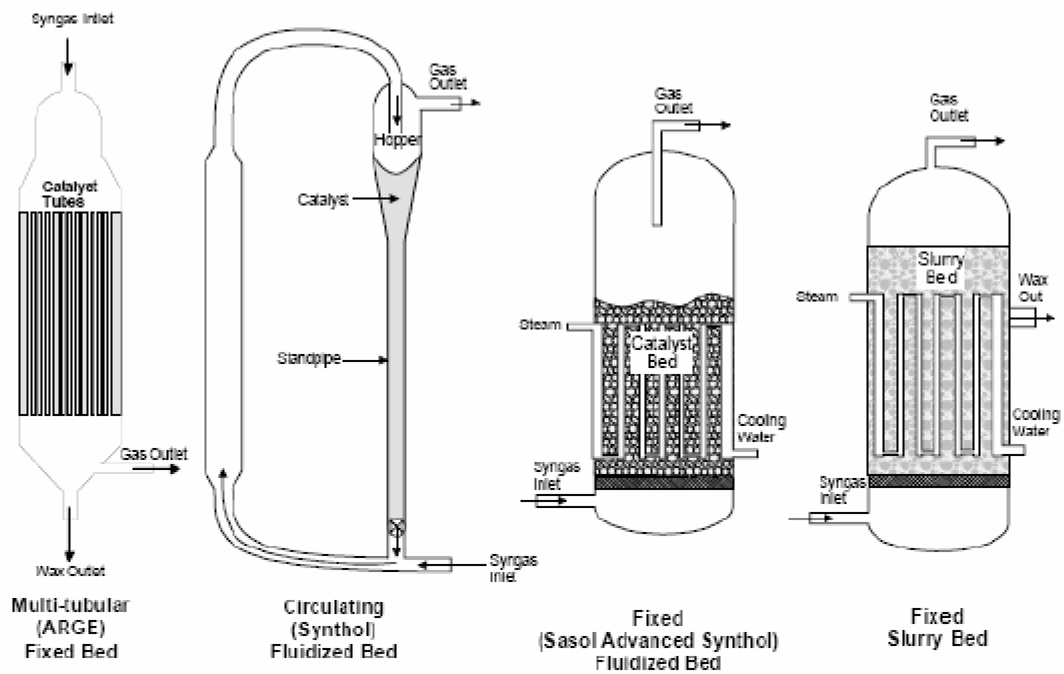
There is both a low temperature FT process (200-240 °C) and a high temperature process (300-350 °C). High temperature FT is capable of making a good grade of gasoline, which the South African company Sasol does on a large-scale basis. Low temperature FT is generally used to make diesel and jet fuels, with a naphtha fraction also resulting.

Fischer-Tropsch synthesis (FTS) makes a large amount of heat from the highly exothermic synthesis reactions, and produces the by-products CO_2 and water. It is necessary to keep the FT reaction temperature within a relatively tight band of tolerance, and temperature is the key FT reactor design parameter. There are four types of FT reactors that have seen general use, as shown in Figure IV-5.

In this study we focus on the low temperature FT process to make diesel fuel, jet fuel, and naphtha. CTL plant projections that were conducted for this study (summarized in Appendix D) assume output of 77% ultra-clean diesel fuel and 33% naphtha. A percentage of FT jet fuel (~30-40% of the total liquids produced) can also be made as a substitute for a portion of the diesel fraction. However, diesel fuel is generally a higher value product, and we thus assume that the diesel product is maximized.[1] FT technology providers include Sasol, Exxon, Rentech, Shell, Syntroleum, BP, Statoil, IFP/ENI, and PetroSA.

[1]It is important to note that some FT technologies may be able to produce a lower portion of naphtha than the 33% noted above. One FT company we contacted claims that their FT reactors will produce only 20-25% naphtha, which would be a distinct advantage.

Figure IV-5
Types of Fischer-Tropsch Reactors



Source: Zero Emission Resource Organisation, "Fischer- Tropsch Reactor Fed by Syngas," www.zero.no/transport/bio/fischer-tropsch-reactor-fed-by-syngas.

Product Upgrading

The hydrocarbon gasses coming out of the FT unit are recycled back as FT reactor feed, after removing the CO_2. The liquids are separated into diesel fuel and naphtha using a simple atmospheric distillation process, and the wax material is sent to a hydrocracker where the wax is converted into naphtha and diesel fuel, with some hydrocarbon gases also resulting (which are also recycled).

Fischer-Tropsch Fuels

As discussed in several other sections of this report, Fischer-Tropsch fuels are ultra-clean, bio-degradable, essentially zero sulfur, with low particulate and NO_x emissions profiles. FT diesel and jet fuels have performance characteristics superior to their conventional distillate counterparts, and zero sulfur gasoline also can be produced. Increased performance from FT fuels translates to lower emissions per mile traveled (including CO_2). More information on the fuels is contained in Section IV.F.3. The following excerpts from an EPA Fact Sheet[1] are illuminating.

[1]*Clean Alternative Fuels: Fischer-Tropsch*, EPA 420-F-00-036, March 2002.

For the past 50 years, Fischer-Tropsch fuels have powered all of South Africa's vehicles—from buses to trucks to taxicabs. The fuel is primarily supplied by Sasol, a world leader in Fischer-Tropsch technologies. Sasol's South African facility produces more than 150,000 barrels of high-quality fuel from domestic low-grade coal daily. The popular fuel is cost-competitive with crude oil-based petroleum products in South Africa. During the next several years, experts predict use of Fischer-Tropsch fuels will grow as a high-end blend stock in California.

The majority of heavy-duty vehicles on our nation's highways today are powered by diesel fuel. This presents enormous opportunities for clean-burning diesel substitutes such as Fischer-Tropsch liquids. Although they have been used to some degree since the 1920s, Fischer-Tropsch fuels are not widely used today—but this could change. From Africa to South America, extensive research and development efforts are under way to commercialize the fuels for vehicle use. More auto manufacturers are viewing Fischer-Tropsch liquids as a viable way to use alternative fuels in diesel engines without compromising fuel efficiency or impacting infrastructure or refueling costs.

Fischer-Tropsch technology converts coal, natural gas, and low-value refinery products into a high-value, clean-burning fuel. The resultant fuel is colorless, odorless, and low in toxicity. In addition, it is virtually interchangeable with conventional diesel fuels and can be blended with diesel at any ratio with little to no modification. Fischer-Tropsch fuels offer important emissions benefits compared with diesel, reducing nitrogen oxide, carbon monoxide, and particulate matter.

In addition, while many alternative fuels require completely separate distribution systems, Fischer-Tropsch fuels can use the existing fuel distribution infrastructure. This means the fuels can be transported in the same ships and pipelines as crude oil. A limited investment will be required, however, to maintain the fuel's purity during distribution.

Emissions Characteristics: Actual emissions will vary with engine design; these numbers reflect the potential reductions offered by Fischer-Tropsch liquids, relative to conventional diesel.

- *Nitrogen oxide reductions due to the higher cetane number and even further reductions with the addi-tion of catalysts.*
- *Little to no particulate emissions due to low sulfur and aromatic con-tent.*
- *Expected reductions in hydrocarbon and carbon monoxide emissions.*

** Estimates based on Fischer-Tropch's inherently "cleaner" chemical properties with an engine that takes full advantage of these fuel properties.*

According to the California Energy Commission, Fischer-Tropsch fuels' superior quality, cost, and ease of distribution could lead to production of 2 to 3 million barrels per day, or 2 to 3 percent of worldwide refinery output, by 2005. According to the California Energy Commission, Fischer-Tropsch fuels can cost up to 10 percent more than conventional diesel, depending on market fluctuations.

Based on available research, there are no significant differences in Fischer-Tropsch fuels' performance versus petrodiesel fuels. In fact, the higher cetane number of Fischer-Tropsch diesel fuel might result in improved combustion; the cetane number is a primary measure of diesel fuel quality. In addition, many alternative fuels require major changes in vehicle engines, but Fischer-Tropsch fuels require no engine modifications. Fischer-Tropsch fuels, however, are slightly less energy dense than petrodiesel, which might result in lower fuel economy and power. Further investigations of fuel compatibility issues need to take place, as well.

Coal-to-Liquids Plant Economics – 16 Cases

On of the groundbreaking facets of this study is an analysis of and cost projections for 16 different coal-to-liquids plants. In this undertaking, three coal types representative of average U.S. bituminous, subbituminous, and lignites have been used as feedstocks to these conceptual FT CTL facilities. In addition to using only coal as feedstocks to these plants, in two of the cases analyzed a mixture of woody biomass and coal was used.

A summary of the economics of each of these plants is provided in Table IV-1. A more detailed report containing detailed costs, descriptions, emissions profiles, and related data is presented in Appendix D. Note that a "threshold" diesel fuel price was computed for each of the projected plants to provide a 15% return on equity investment. This finished product "threshold" price was translated back to a crude oil equivalent price using the assumption that ultra-clean FT diesel will sell for a premium of at least 1.3 times crude oil. Also note that we have used the "recycle" configuration plant costs as input for the macroeconomic models in the study, as these provide lower costs than the "once through" configurations – see Figure IV-6

Two general process configurations are used in this CTL analysis: (1) a simple recycle and (2) a once-through configuration. Each of these pertains to the way the FT synthesis reactor system and its associated product recovery and upgrading sections are arranged and operated. A general description of the simple recycle and once-through configurations follows.

The Simple Recycle Configuration

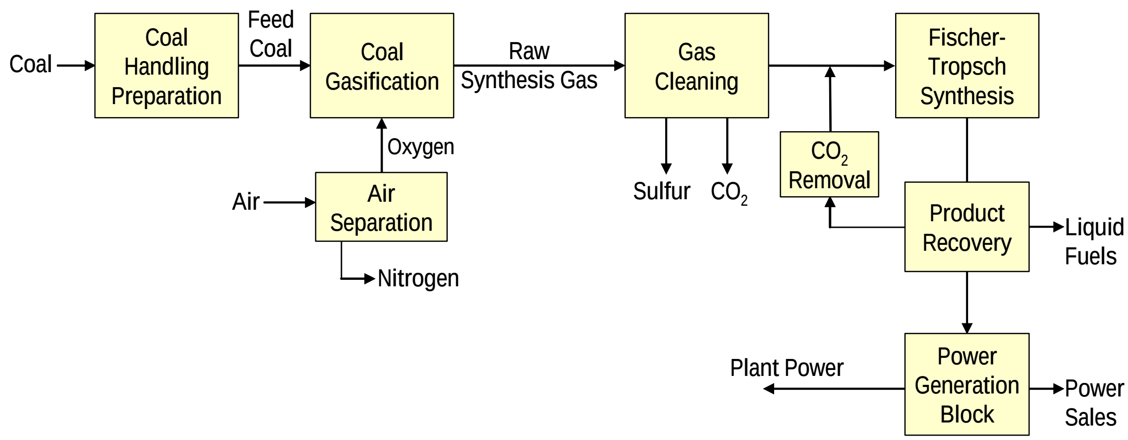
Figure IV-6 shows a generic block flow diagram of a simple recycle CTL configuration. In this configuration the feed coal is gasified with oxygen to produce a raw synthesis gas consisting of carbon monoxide and hydrogen. This raw synthesis gas is cleaned to remove contaminants such as acid gases and the cleaned gas is then sent to FT synthesis. In the FT synthesis reactor the synthesis gas is reacted over catalysts to produce hydrocarbons. Complete conversion of the synthesis gas to hydrocarbons does not occur in one pass through the FT reactors. In the recycle configuration the effluent from the FT reactors is cooled to recover the portion constituting liquid fuels and the unconverted synthesis gas is recycled back to the FT reactors to increase the conversion to fuels. The carbon dioxide produced in synthesis is removed in the recycle loop. A portion of the FT effluent containing unconverted synthesis gas and light hydrocarbon gases is sent to the power generation section of the plant to provide the electric power needs of the facility.

Table IV-1
CTL Plant Economics

Plant Case No.	Capacity (BPD)	Config.	Coal Type	Export Power (MW)	Capital Required ($/DB)(1)	Diesel Selling Price COE Basis ($/B)(2)	Diesel Selling Price ($/B) (3)	Efficiency (% HHV)
1	10,000	Recycle	Bituminous	27	$88,700	54.9	71.36	47.1
2	10,000	Once-through	Bituminous	241	$120,400	60.69	78.90	44.1
3	30,000	Recycle	Bituminous	204	$74,900	45.96	59.74	48.1
4	30,000	Once-through	Bituminous	537	$87,500	46.67	60.67	47.1
5	60,000	Recycle	Bituminous	386	$70,700	44.02	57.23	47.6
6	10,000	Recycle	Subbituminous	19	$87,300	46.29	60.18	50.7
7	10,000	Once-through	Subbituminous	162	$112,400	50.5	65.65	44.2
8	30,000	Recycle	Subbituminous	146	$71,900	37.14	48.28	50.3
9	60,000	Recycle	Subbituminous	44	$62,100	34.62	45.01	51.3
10	10,000	Recycle	Lignite	6	$101,500	55.71	72.43	43.9
11	10,000	Once-through	Lignite	163	$128,200	60.01	78.02	40.8
12	30,000	Recycle	Lignite	91	$83,100	45.15	58.70	45.5
13	30,000	Once-through	Lignite	432	$98,500	46.21	60.07	43.5
14	60,000	Recycle	Lignite	9	$72,000	41.19	53.55	46.7
15	10,000	Recycle	Bituminous, 10% biomass	28	$89,700	55.32	71.91	46.7
16	10,000	Recycle	Bituminous, 20% biomass	29	$90,900	55.79	72.52	46.2

Source: Mitretek, 2006.

Figure IV-6
Generic Simple Recycle Coal to Liquid Configuration



The Once-Through Configuration

The once-through configuration is shown schematically in Figure IV-7. The once-through configuration differs from the simple recycle configuration in that the synthesis gas is passed once-through the FT reactors and the FT tail gas is sent directly to the power generation block after carbon dioxide removal. This results in a larger net electric power output than the recycle configuration.

CTL Cases Analyzed

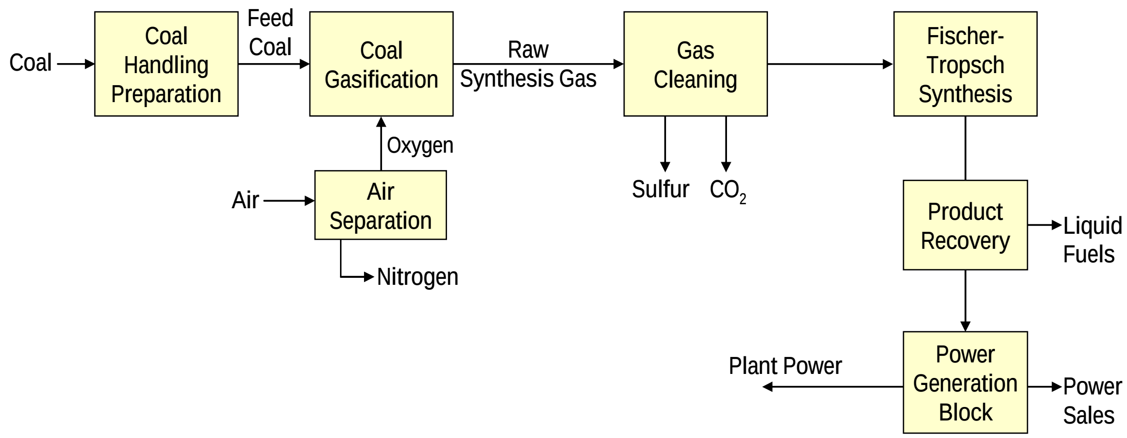
A total of 16 CTL cases were analyzed in this study. Although the plants process a particular coal it should be noted that these conceptual plants are generic and not site specific. The objective of analyzing this suite of cases was to determine the impact of coal type, plant configuration, and plant size on performance and economics.

Feedstock Analyses

Bituminous coal was selected to represent a typical U.S. bituminous coal. The coal is fed to the plant as-received (AR) and has a heating value of 11,800 Btu/lb (HHV). The average subbituminous coal assumed contains 30 percent moisture on an AR basis. In order to feed this coal to a dry feed entrained gasifier it is assumed that this coal must be dried to 10 weight percent moisture. The as-fed (AF) coal has a heating value of 10,913 Btu/lb (HHV).

The representative lignite coal contains 36.5 percent moisture (AR) and 9.84 percent mineral matter, and has a carbon content of only 37 weight percent. It is assumed that this lignite must be dried to 10 weight percent moisture to enable it to be fed to a high pressure dry feed entrained gasifier. The AF analysis has a heating value of 8,978 Btu/lb (HHV). More detailed coal specifications are provided in Appendix D.

Figure IV-7
Generic Once-Through Coal to Liquid Configuration



A representative analysis of the woody biomass configuration is given in Appendix D. On a dry basis this material contains about 48 weight percent carbon and almost 44 percent oxygen. It is assumed that this biomass is dried to 15 percent moisture before it is mixed with coal and fed to the gasifier. The AF biomass has a heating value of 7,104 Btu/lb (HHV).

Conceptual CTL Plant Process Units

Regardless of size, overall configuration, and feedstock, the CTL conceptual plants analyzed all have essentially the same process units in common. These were shown in the block flow diagrams in Figures IV-6 and IV-7. Component plant process operations are describes in detail in Appendix D. These process areas include:

- Coal Preparation, Drying and Grinding
- Coal Slurry (in some cases)
- The Air Separation Unit
- The Gasification Systems
- Gas Cooling, Raw Water Gas Shift, Carbonyl Sulfide Hydrolysis, and Mercury Removal
- Acid Gas Removal
- Hydrogen Recovery
- Sulfur Polishing
- Fischer-Tropsch Synthesis
- FT Product Upgrading
- Carbon Dioxide Removal in Reycle Loop
- Power Generation Block
- Balance of Plant (BOP) Units

IV.C. Oil Shale

Oil Shales can be produced by two generalized processes: Mining (surface or underground) with surface retorting, or in-situ processing.

IV.C.1. Mining

Oil shales for surface retorting can be surface mined or deep-mined, and surface mining is likely to be used for those zones that are near the surface or that are situated with an overburden-to-pay ratio of less than about 1:1. Figure IV-8 depicts locations accessible to surface mining in Utah, showing the surface outcrop along the southern margins of the formation. Numerous opportunities exist for the surface mining of ore averaging more than 25 gallon/ton, with overburden-to-pay ratios of less than 1, especially in Utah.

In underground mining, room and pillar mining is likely to be used for resources that outcrop along steep erosions, and horizontal adit, room and pillar mining has been used successfully by Unocal. Deeper and thicker ores will require vertical shaft mining, modified in-situ, or true in-situ recovery approaches.

IV.C.2. Surface Retorting Technology

Once the shale has been mined, it must be heated to temperatures between 400 and 500 degrees centigrade to convert – or retort -- the kerogen and create shale oil and combustible gases. Numerous approaches to surface retorting were tested at pilot and semi-works scales during the 1970s and 1980s, and two types of surface retort facilities, vertical and horizontal, offer significant promise.

Vertical retorts have been used with increasing success and efficiency since the early days of oil shale operations. The Gas Combustion Retort (GCR), developed by Cameron Engineers and the U.S. Bureau of Mines, is one of the most successful vertical retorts (Figure IV-9). GCR achieves high retorting and thermal efficiencies and requires no cooling water, an important feature in semi-arid regions. A variation called Petro-Six is operating in Brazil and another variation, the Paraho process, is being considered for a major non-U.S. oil shale development project.

Horizontal retorts heat the shale through a horizontal kiln. The TOSCO II preheated shale in a bed and then circulated the shale in a hot rotating drum with heated ceramic balls.[1] The Alberta Taciuk Processor (ATP) is another variation of the horizontal retort; however, design issues and scale-up limitations have raised critical questions about ATP's viability for use in large scale commercial operations.

[1]This technology was terminated in 1972.

IV.C.3. In-Situ Processing

In-situ processing involves heating the resource in-place, underground. Various approaches have been proposed and tested, including true in-situ and modified in-situ. True in-situ processes involve no mining: The shale is fractured, air is injected, the shale is ignited to heat the formation, and shale oil moves through fractures to production wells -- Figure IV-10. There are some difficulties in controlling the flame front which can leave some areas unheated and some oil unrecovered.

Figure IV-9: Gas Combustion Retort

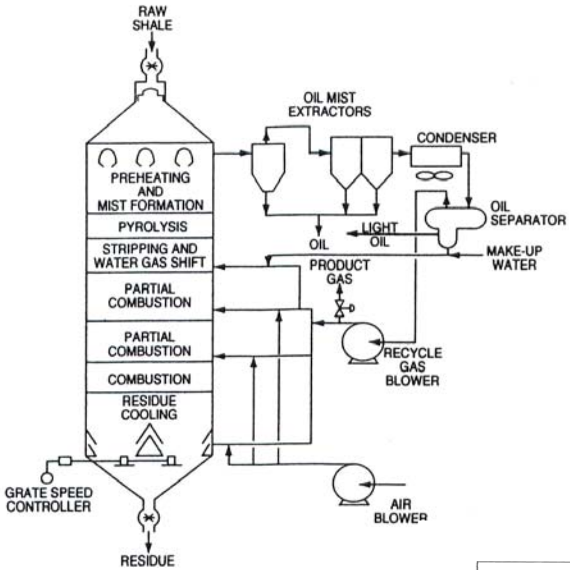
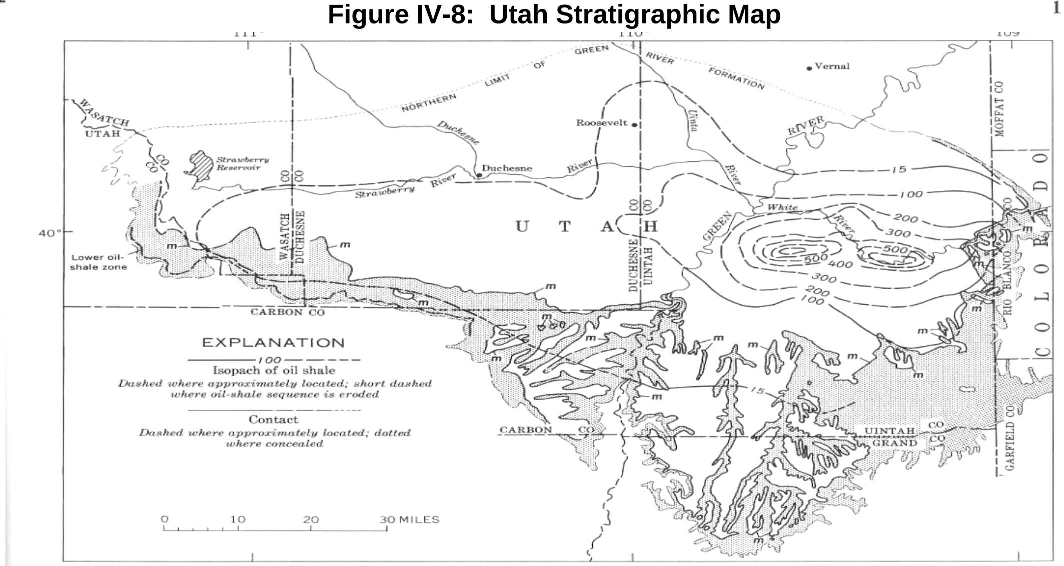


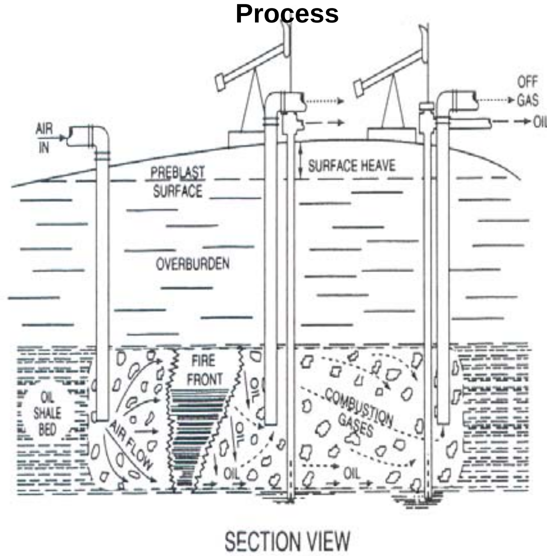
Figure IV-8: Utah Stratigraphic Map



Modified in-situ (MIS) involves mining below the target shale before heating and requires fracturing the target deposit above the mined area to create void space of 20 to 25 percent. The shale is heated by igniting the top of the target deposit. MIS processes can improve performance by heating more of the shale, improving the flow of gases and liquids through the rock, and increasing the volumes and quality of the oil produced.

Shell Oil is researching a novel in-situ heating process that shows promise for

Figure IV-10: Conventional True In-Situ Process



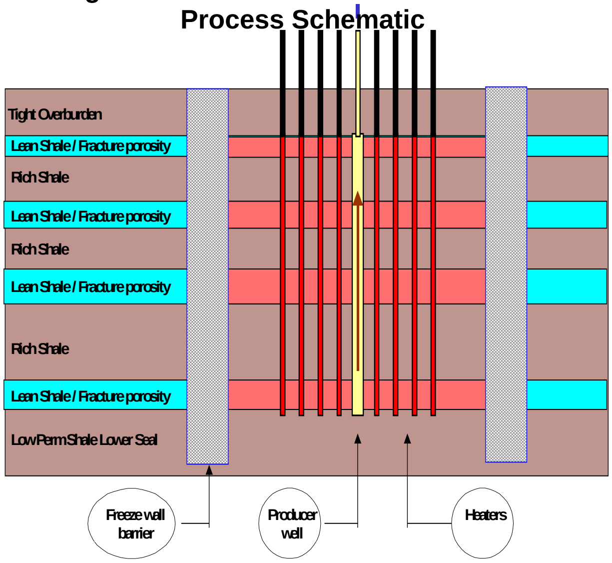
recovering oil from rich, thick resources lying beneath several hundred to more than 1,000 feet of overburden. The process uses electric heaters placed in closely spaced vertical wells to heat the shale for two to four years – Figure IV-11. The slow heating creates microfractures in the rock to facilitate fluid flow to production wells, and the resulting oil and gases are moved to the surface by conventional recovery technologies. Shell's In-Situ Conversion Process (ICP) slow heating is expected to improve product quality and recover shale oil at greater depths than other oil shale technologies, and in addition, the ICP process may reduce environmental impacts by eliminating subsurface combustion. An innovative "freeze wall" technology is being tested to isolate the production area from groundwater intrusion until oil shale heating, production, and post production flushing has been completed. Shell is operating a modest field research effort in northwestern Colorado's Piceance Basin to test ICP's viability. The critical challenges facing the ICP technology include development of reliable heater technology, improvements of downhole heater durability, and validation of the efficacy of freeze wall technology.

Utilizing in-situ processing, there are locations that could yield in excess of one million barrels of oil equivalent per acre and require, with minimum surface disturbance, fewer than 23 square miles to produce as much as 15 billion barrels of oil over a 40-year project lifetime.

IV.C.4. Development Status

There is currently no commercial oil shale production in the United States. Oil shale industry development in the U.S. was interrupted in the early 1980s principally due to declining oil prices, not technology or environmental concerns. Major investments by industry and government resulted in thorough understanding of oil shale resources and the development and testing of a broad spectrum of surface retorting and in-situ technologies for converting oil shale from rock to liquid fuels. The lessons learned and the technologies developed from these efforts remain available, and oil shale efforts elsewhere in the world have added to the body of knowledge and technology available.

Figure IV-11: Shell In-Situ Conversion Process Schematic



The critical hurdle for domestic oil shale production is successful development and operation of a first-generation plant at commercially-representative scale. The best existing technologies for producing U.S. oil shales have not yet been tested beyond the pilot scale, and demonstration of first-generation technologies will be required at a commercially-representative scale before significant private investment will lead to commercial production. Several ongoing research and pilot projects could lead to commercial scale production within the next decade. However, a broad range of significant impediments and uncertainties must be resolved to attract the major private investment that will be required to advance technologies to demonstration at commercial scale and to design, build, and operate commercial scale oil shale plants. These impediments and uncertainties include access to resources on public lands, technology performance and efficiency, capital and operating costs, and oil price volatility.

Several recent developments have occurred as a result of the Energy Policy Act of 2005, which directed DOE to establish a commercialization program. Congress directed DOE to assess the readiness and potential of existing oil shale technologies for demonstration and implementation at commercial scale. In addition, the Department of the Interior Bureau of Land Management (BLM) has initiated a Research, Development and Demonstration Leasing Program for Oil Shale.[1]

Congress directed the Department of the Interior to conduct a programmatic environmental impact statement (PEIS) for a commercial oil shale and tar sands leasing program and has directed BLM to prepare regulations to facilitate commercial leasing. Congress directed DOE to develop an integrated Commercial Strategic Fuels Development Program that focuses on oil shale and tar sands as well as heavy oil, enhanced oil recovery, and coal liquids.

While, as noted, there is currently no commercial production of oil shale in the U.S., higher oil prices and the expectation that public actions will be taken to overcome other major development impediments have stimulated oil shale interest and activity on the part of several major and independent energy and technology companies. Several private companies are currently conducting R&D efforts that could lead to field pilots, semi-works, or commercial-scale demonstration projects within a decade, and commercial scale operations soon thereafter. For example:

- Major oil companies appear to be focusing R&D on promising in-situ approaches for application in the U.S. Shell Oil, Chevron, and ExxonMobil and a smaller Texas company have been selected for BLM RD&D leases to develop and test in-situ processes in Colorado. Shell's research project could yield a corporate decision to proceed to demonstration at commercially-representative scale by 2010, with production beginning by 2016 and reaching 500,000 bpd by 2022.
- Oil Tech and Oil Shale Exploration, LLC have announced competing plans for R&D of surface projects at the White River site in Utah. Oil-Tech's surface demonstration project in Utah could be functional at commercially-representative scale of 10,000 bpd by 2010. If successful, it could be expanded to 100,000 bpd by 2015.

[1]BLM received 19 lease applications and has selected eight (six in-situ and two surface) for lease negotiations.

Current mining and oil shale conversion technologies are adequate to initiate an industry; however, most technologies still require demonstration at commercially-representative scale. As in other industries, including Alberta's tar sands, knowledge advancements and technology improvements gained in "1st generation" operations can be expected to significantly reduce costs and improve the efficiencies of "next-generation" projects. With decisive leadership, appropriate public financial, regulatory, and technology support, and effective collaboration between industry, government, and other stakeholders, an aggressive goal of oil shale production approaching 2 MM bpd by 2020 may be possible.

IV.C.5. Development Economics

The major barriers to U.S. oil shale industry commercialization are economic: High front-end capital investments will be required and long lead-times will precede commencement of revenue streams. Risks associated with the price-volatility of conventional petroleum and the uncertainty of capital and operating costs (including environmental costs) in commercial-scale technologies need to be reduced to facilitate capital formation and project investment.

The major components of an oil shale operation's capital costs for a mining and surface retorting facility are mine development, retorting, and upgrading facilities and infrastructure projects. For in-situ processing the major capital costs are for subsurface facilities, including wells or shafts to access and heat the shale, recover liquids and gases, and isolate and protect subsurface environments, and surface facilities including production pumps and gathering systems, process controls, and upgrading facilities. The capital cost for a 100,000 bpd surface retort facility has been estimated to about $4 billion, with the first-generation plant likely to be more than $4 billion and a mature-industry plant likely to be a little less.[1] Operating costs include mining, labor, energy costs, and administration. With time, operating costs will likely decrease as operations gain economies of scale, and experience, improved understanding, design enhancements, and improved operating efficiency will lead to the cost reductions. If major impediments and uncertainties can be resolved, projects can be initiated to demonstrate first-generation in-situ and surface technologies at commercially representative scale. Representative oil shale facility costs are given in Table IV-2.

[1] U.S. Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, "Oil Shale Fact Sheet," 2006.

Table IV-2
Oil Shale Facility Costs
(Billions of 2005 dollars, normalized to a 100,000 bpd facility)

	In-situ Facilities		**Retort Surface Facilities**		**Retort Underground Facilities**	
	Construction Costs	O&M Costs	Construction Costs	O&M Costs	Construction Costs	O&M Costs
First Plant	$3.2	$0.7	$4.1	$0.5	$4.3	$0.5
Nth Plant (N=3)	$2.7[a]	$0.53[b]	$2.9[c]	$0.3[d]	$3.0[e]	$0.3[f]

[a]In-situ plant construction costs decline by 15 percent by the Nth plant.
[b]In-situ plant O&M costs decline by 25 percent by the Nth plant.
[c]Retort surface facility construction costs decline by 30 percent by the Nth plant.
[d]Retort surface facility O&M costs decline by 40 percent by the Nth plant.
[e]Retort underground facility construction costs decline by 30 percent by the Nth plant.
[d]Retort underground facility O&M costs decline by 40 percent by the Nth plant.

Source: U.S. Department of Energy, Office of Petroleum Reserves.

IV.D Enhanced Oil Recovery

IV.D.1. EOR Technologies Overview

As noted in Chapter III, EOR techniques theoretically offer prospects for producing 80+ billion barrels of “stranded” oil under favorable conditions. Four major categories of EOR have been found to be commercially successful to varying degrees:

- Thermal recovery (e.g., steam injection) introduces heat into the reservoir to lower the oil's viscosity, thereby improving the oil's ability to flow from the reservoir. Thermal techniques account for over 50 percent of the U.S. EOR production.
- Chemical injection may be used to enhance the characteristics of the water in a water flood, either to increase the water's viscosity, making it less likely to by-pass reservoir oil and leave part of the oil behind, or to lower the interfacial tension between the water and the oil, "lubricating" the path for the oil to flow from the reservoir. Chemical techniques account for less than one percent of U.S. EOR production.
- Gas injection uses gases such as natural gas, nitrogen, or carbon dioxide to displace additional oil from the reservoir or to dissolve in the oil causing it to expand while simultaneously lowering its viscosity, both of which improve the oil's ability to flow from the reservoir. Gas injection accounts for close to 50 percent of U.S. EOR production.
- Other processes, such as microbial EOR, are being researched, but do not currently contribute much to oil production.

Each of these techniques involves costs that are higher than typical conventional secondary recovery methods and involve additional risk because of the sensitivity of the processes to some of the reservoirs' unknown characteristics.

Thermal Processes

Viscosity is a measure of a liquid's ability to flow and varies widely among crude oils. Some crude oils flow like road tar, whereas others flow as readily as water, and with increased viscosity oil becomes increasingly difficult to recover with primary or secondary production methods. The viscosity of crude oil decreases dramatically as temperature increases, therefore, thermal oil-recovery processes are used to heat the oil to make it flow more easily. Fluids injected into the reservoir heat the oil to mobilize it and then drive the oil to wells where it can be produced. The injected fluids may be steam, hot water, or air – the latter being injected for in situ combustion of the oil to provide the heat.

Historically, steam injection has been the most advanced and most widely adopted EOR process, having been successfully used in California heavy oil fields since the 1960s. The first steam projects used cyclic injection, while later projects employed steam drives. In the former method (also called "huff-and-puff"), high-pressure steam and/or hot water is injected into a well for a predetermined period of time (the "huff") during which the reservoir becomes warm and the oil becomes less viscous. Injection is then suspended and the oil is allowed to flow back into the well bore and is pumped out (the "puff"). This cyclic process is repeated until the resulting yield falls to an uneconomic level.

The steam drive (or steam flooding) method involves continuous injection of steam and/or hot water in much the same way as unheated water is injected in water flooding. Oil is produced from a nearby producing well or wells. During a steam drive, the reservoir near the injection well becomes heated and the oil becomes less viscous -- as in the case the cyclic method. In this case, however, the steam and/or water injection is continued without cycling. During this process, a steam zone is created in the part of the reservoir nearest the injection well, while immediately ahead of this is a hot-water zone where the steam has condensed. Within and in front of the hot-water zone is a region of warm oil that is being moved by the water and steam toward a producing well. Cyclic steam injection is often tried before a full-scale steam drive is initiated, and this serves two purposes: Providing an indication of the technical feasibility of the process, and preconditioning the reservoir, which may help improve the efficiency of the subsequent steam drive.

In-situ combustion (sometimes called "fire flooding") is another form of thermal EOR in which air is injected, typically into a heavy oil reservoir to accomplish objectives similar to the steam drive process. Air, sometimes heated, is injected into the reservoir, causing the oil to ignite spontaneously. Part of the oil is consumed by burning, but hot combustion gases invade the surrounding reservoir, heating the oil and vaporizing the volatile components of the oil. The oil is actually distilled as it moves away from the heated part of the reservoir toward the cooler parts of the reservoir near the producing wells.

An improvement to the basic process utilizes water injection along with the air injection to create "wet combustion." Without water injection, much of the heat generated from the combustion is left in the reservoir rock behind the burn-front, and part of this heat is recoverable by water injection, often as alternating slugs of water and air. The water is vaporized and moves through the combustion zone to heat the reservoir and oil ahead and, with proper regulation of the proportion of water and air, the process has a higher thermal efficiency than it would without water injection. While the method possesses an energy efficiency advantage due to the heat being generated in the reservoir itself, thereby avoiding heat losses in the well bore and surface lines, its complexity has kept it from enjoying the same success as the steam processes. Variations of the basic technique have been researched, as have high-temperature foams and polymers, to achieve better efficiency and process control.

Chemical Processes

Chemical EOR uses various chemicals to improve on the basic water flooding process. The chemicals may be as simple as sodium hydroxide or a complex mixture of surface-active agents and stabilizers. An early EOR system with great promise involved the creation of "micro-emulsions" to perform a number of beneficial functions simultaneously. Also known as micellar flooding, the process had the potential to increase the effective viscosity of water, reduce the effective interfacial tension of the injected and produced phases, and increase the effective reservoir oil saturation. Any one of these benefits had the potential for producing additional oil after conventional water flooding, and under ideal conditions these micro-emulsion systems could displace from the reservoir rock virtually all of the oil contacted. Even so, the process has remained marginally economic, largely due to the expense of the chemical systems needed to cope with less-than-ideal, real reservoirs.

Polymer flooding can be described as a chemically-augmented water flood where small concentrations of chemicals (polymers) are added to injected water to increase its effectiveness in displacing oil. The change in effectiveness is due mainly to increased water viscosity, and thus lower mobility, which in turn increases both displacement efficiency (more oil pushed from the rock pores) and areal sweep efficiency (larger area of the reservoir swept by a given injection fluid volume). By proper design, polymer fluids can be injected selectively into rock layers of varying permeability to improve the vertical injection profile. Polymers may also be combined with other oil recovery processes when viscosity-control is needed to stabilize the displacement system.

Alkaline flooding involves water solutions of certain chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate, which are strongly alkaline and will react with constituents in some crude oils or reservoir rocks to form detergent-like materials. These materials then make displacement of the oil much easier.[1] When

[1]Mixtures of these chemicals also are marketed as oxygen-based stain removers, deodorizers, laundry

alkaline chemicals are injected into certain reservoirs, oil recovery is enhanced by reduction of interfacial tension, spontaneous emulsification, and/or wettability changes (i.e., the forces of attraction between the reservoir rock and its contained fluids change in magnitude and relativity). The process, while similar, is much less expensive than the micro-emulsion systems because of the lower-cost chemicals.

Gas Injection/Solvent Processes

Certain gas solvents can enhance recovery by dissolving some of the oil into the injected gas. In effect, the injected gas acts as a solvent. The resulting solution is recovered, and the oil and solvent are then separated by a distillation type of process so that the oil can be further refined and the solvent reused. In the process, the injected solvent may cause an "oil bank" to form, which can then be driven to producing wells by injecting water into the reservoir -- water is generally much cheaper than solvents. When liquefied petroleum gases and other volatile hydrocarbons are available as surplus commodities, they may be used as solvents for oil recovery since they are mutually and completely soluble (i.e., "miscible") with many reservoir oils. Hydrocarbons are becoming less common as the injection solvent because they are rarely surplus commodities and command relatively high prices.

Because it is less expensive than hydrocarbons, carbon dioxide (CO_2) is now the most popular fluid for injection, even though it is usually not directly miscible with reservoir oils. It does, however, have the ability to dissolve with some of the more volatile hydrocarbons that make up the oil, resulting in a mixture of CO_2 and hydrocarbons that is miscible with the reservoir oil. The lowest pressure needed to develop this mixture is called the minimum miscibility pressure (MMP), and the MMP is a function of the composition of the reservoir oil, the reservoir temperature, and the depth. Generally speaking, warmer, deeper reservoirs result in higher MMPs.

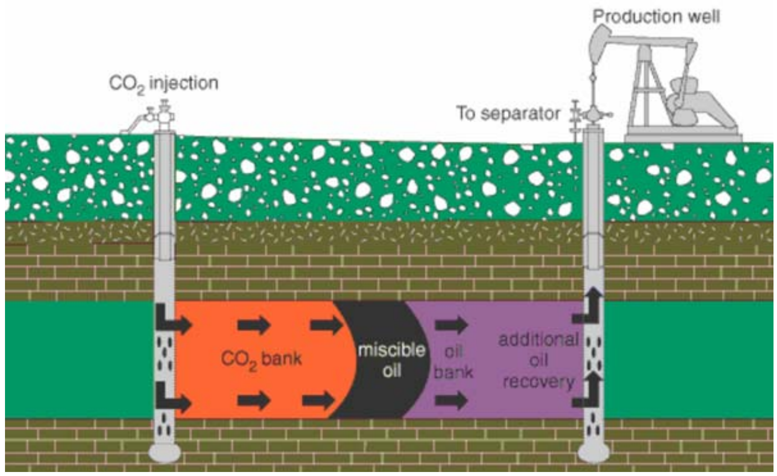
The CO_2-EOR processes may involve either miscible or immiscible displacement of the residual oil left in the reservoir after primary and secondary recovery operations – see Figure IV-12. Both processes can be very effective in recovering oil, but the maximum potential for oil recovery is obtained through miscible displacement.

Immiscible displacement by CO_2 can be very effective, relying primarily on oil expansion and oil viscosity reduction, which combine to improve the mobility of the oil and allow it to be displaced from the reservoir by CO_2 and/or other injected fluids. The more effective miscible displacement process also expands the oil and reduces its viscosity, but adds a solvent action (the miscible aspect) that further increases the efficiency of the process. CO_2-miscible slim-tube laboratory experiments have recovered virtually 100 percent of the oil in the slim-tubes, but field experience invariably recovers a much lower percentage because of less favorable geometry and reservoir heterogeneity.

---

additives, etc.

Figure IV-12: CO_2 EOR Operation



Source: Kansas Geological Survey Website

Other EOR Processes

Many other processes for improving oil recovery have been developed and patented, but few have achieved much success. Processes have involved the application of different forms of energy to the reservoir, such as electricity, microwaves, sound, and ultrasound attempting to mobilize the oil. The only one of these technologies that is receiving significant contemporary interest is microbial enhanced oil recovery (MEOR), which has been researched for many years but still is not very well understood. Under the right conditions, natural bacteria present in many reservoirs are capable of feeding on crude oil to produce a variety of gases and chemicals that can favorably affect crude oil and reservoir characteristics. Most work to date, however, has been confined to the laboratory. Even though some of the laboratory results have appeared to be promising, companies have been reluctant to try scaling up to a field-scale application, but an ongoing oilfield development project by Statoil may help advance MEOR indirectly.[1] Statoil hopes to increase its oil recovery by as much as six percent for its MEOR project, or 32 million barrels. Thus far, MEOR has not produced significant amounts of oil, but the process has potential.

IV.D.2 CO_2 EOR Processes

CO_2 EOR's recovery efficiency is a combination of: (1) the ability to displace oil "microscopically" within the reservoir pores, (2) the ability to sweep clean a wide area of the reservoir, and (3) the ability to penetrate and contact oil within all oil-bearing strata in the vertical section of the reservoir. The microscopic displacement of oil from the

[1]Statoil is injecting sodium nitrate and other inexpensive chemicals into a reservoir to discourage the activity of sulfate-reducing bacteria while simultaneously encouraging the development of nitrate-reducing bacteria colonies. Although the main reason for manipulating the bacteria is to reduce the formation of hydrogen sulfide, the bacteria also produce multiple oil-mobilizing agents in the form of solvents, organic acids, gases and surfactants.

reservoir is greatly affected by three factors: the oil's viscosity, its surface tension characteristics, and the connectivity of the various "strands" of oil inside the rock. The latter of these factors may be the most difficult to deal with because it is the result of a combination of oil and rock properties that are largely out of the operators control.

The injection of CO_2 into the reservoir immediately affects the oil's viscosity and its volume because the CO_2 goes into solution with the contacted oil, swelling the oil and decreasing its viscosity. The reduced viscosity allows the oil to flow more freely, making it easier to displace from the reservoir. As the oil swells, it occupies more and more of the pore space in the rock, pushing water out of its way and joining strands of trapped oil together. The oil, occupying more pore space and becoming more continuous within the reservoir, becomes mobile and subject to easier displacement from the reservoir.

Miscibility, the ultimate goal in most CO_2-EOR projects, occurs when enough CO_2 has been injected at an adequate pressure to cause the development of a single-phase transition zone between the reservoir oil and the CO_2. As the CO_2 is injected, it goes into solution in the oil while some of the less-heavy components of the crude oil are extracted into the CO_2 gas phase, and this process continues until the interface between the hydrocarbon-rich CO_2 phase and the CO_2-rich hydrocarbon phase disappears. The process is often referred to as multiple-contact miscibility because it does not happen instantly (single-contact) and requires continuous or repeated injection of CO_2. This accomplishes the third objective of the CO_2-EOR process, the modification of interfacial tension.

Other factors that affect the process are mostly related to the reservoir itself, affecting the "macroscopic" displacement process, and are inherent to most of the other EOR processes as well. Most reservoirs are composed of different layers of rock that have different characteristics; e.g., different permeabilities or different fluid saturations. High permeability layers may "steal" the injected fluids so that oil is bypassed in the less permeable zones. Layers with high water saturations may also act as thief zones because it is easier to displace the water than to enter a viscous-oil zone. Thick reservoirs with good vertical permeability will allow the CO_2 to rise vertically and ride along the top of the reservoir, with oil recovery coming only from the uppermost few feet of the reservoir. Natural fractures in a reservoir will often have high fluid conductivity and can allow injected CO_2 to bypass the reservoir rock that contains the bulk of the oil. These potential problems can sometimes be overcome by selectively injecting into only the most favorable layers, by innovative use of well completion geometry to take maximum advantage of gravitational forces or permeability anisotropy, or by judicious use of polymers to divert flow to where it is wanted.

One of the process's major drawbacks is CO_2's low viscosity, which is much less than 1 centipoise (cp.) compared to the viscosity of the oil (usually much greater than 1 cp.) that is being replaced; thus, there exists the potential problem of bypassing part of the oil in the reservoir. This problem can sometimes be overcome by using water or polymer solutions in conjunction with the CO_2 to "slow it down." There can also be problems associated with incomplete miscibility with the crude oil, in particular the inability to maintain the oil's heavy components in solution. As a result, the process may cause the precipitation of waxes, resins, or asphaltene compounds that could plug parts of the reservoir. However, even with these potential problems CO_2-EOR is being increasingly used in the field because it is effective where other techniques are not, and is generally less complex than the other applicable methods. Table IV-3 shows screening criteria for the various EOR technologies and thus illustrates the versatility of CO_2 for enhanced recovery, compared to the other methods.

Table IV-3
Desirable Oil and Reservoir Characteristics for EOR
(screening criteria)

EOR method	°API	Viscosity [cp]	Crude Oil	Oil saturation [% PV]	Formation type	Net thickness [m]	Permeability [mad]	Depth [m]	T [ºC]
N_2 (&flue gas)	>35	<0.4	High %C1-C7	>40	Sandstone, Carbonate	Thin unless dipping	-	>2000	-
Hydro-carbon	>23	<3	High %C2-C7	>30	Sandstone, Carbonate	Thin unless dipping	-	>1350	-
CO_2	>22	<10	High %C5-C12	>20	Sandstone, Carbonate	-	-	>600	-
Mackellar/ polymer/ alkaline	>20	<35	Light to inter-mediate	>35	Sandstone	-	>10	<3000	<95
Polymer flooding	15-40	10-150	-	>70	Sandstone	-	>10	<3000	<95
Combustion	>10	<5000	-	>50	High porosity sand/sandstone	>3	>50	<4000	>40
Steam	>8	<200,000	-	>40	High porosity sand/sandstone	>6	>200	<1500	-

IV.D.3. CO_2 EOR Economics

The estimate/expected ranges of EOR oil production for 1) miscible CO_2 EOR projects and 2) immiscible CO_2 EOR projects per ton of new (not recycled) CO_2 injected over the life of a project are::

- Miscible Case. The average daily production of oil per average daily injection (net, not counting re-cycled CO_2) is about 1 bbl of oil for every 6,000 scf of CO_2, or about 3 bbl per ton. Modelers have estimated the range to be from about 4,000 scf to 10,000 scf per bbl, and a viable estimate is thus a range of about 1.5 to 4.5 bbl per net ton of CO_2 injected.[1]

- Immiscible Case. There have not been as many field tests as there have been for the miscible case. A number of immiscible natural gas and nitrogen injection EOR projects have been undertaken, but CO_2 is different and considerably more effective. The estimated immiscible range is 10,000-20,000 scf of CO_2 per barrel of oil, or about 0.5 to 2 bbls per net ton of CO_2 injected.

Estimated typical life-cycles for a miscible and an immiscible project averaging about 3,000 bpd are given in Tables IV-4 and IV-5.

Table IV-4
CO_2-EOR Project Life Cycle -- Miscible[2]

Year End	New CO_2 tons/day	Recycled CO_2 tons/day	Oil Production bbls/day	Days Onstream
1	0	0	0	0
2	1600	0	0	360
3	2400	0	2,500	360
4	2500	0	7,000	360
5	2600	400	7,500	360
6	2200	500	7,000	360
7	1900	900	5,800	360
8	1600	1,400	4,800	360
9	1400	1,700	3,970	360
10	1200	2,000	3,290	360
11	1000	2,300	2,720	360
12	900	2,400	2,250	360
13	800	2,600	1,860	360
14	700	2,700	1,540	360
15	600	2,900	1,280	360
16	0	1,680	1,060	360
17	0	970	880	360
18	0	560	730	360
19	0	320	600	360
20	0	190	500	360

[1]The conversion range is one ton of CO_2 equals 17,100-17,600 scf.
[2]A somewhat more constant input of fresh CO_2 is possible and perhaps likely, based on contractual terms.

Table IV-5
CO_2-EOR Project Life Cycle -- Immiscible[1]

Year End	New CO2 tons/day	Recycled CO2 tons/day	Oil Production bbls/day	Days Onstream
1				
2	2550	0	0	360
3	3820	0	1890	360
4	3980	910	5300	360
5	4140	1140	5680	360
6	3500	2050	5300	360
7	3020	3180	4390	360
8	2550	3870	3640	360
9	2230	4550	3000	360
10	1910	5230	2500	360
11	1590	5460	2070	360
12	1430	5910	1710	360
13	1270	6140	1410	360
14	1110	6590	1160	360
15	950	3820	980	360
16	0	2210	800	360
17	0	1270	660	360
18	0	730	550	360
19	0	430	450	360
20	0	250	390	360

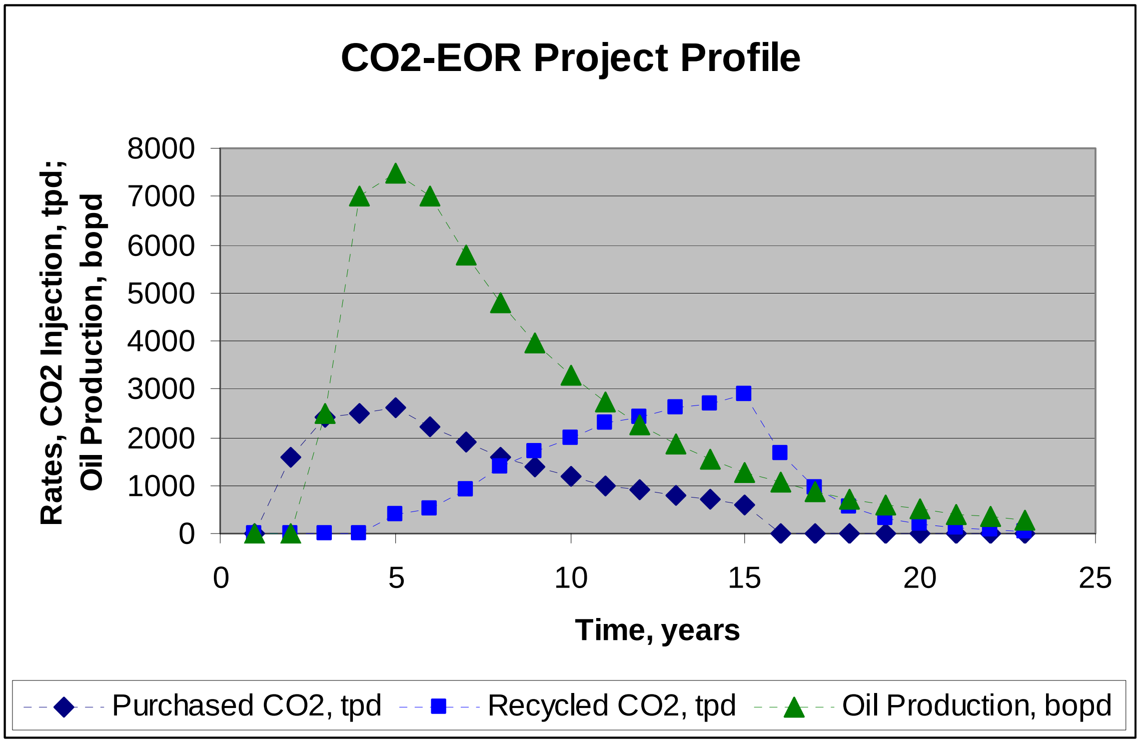
Note: This is not equivalent to the miscible project illustrated in Table IV-4. The 3,000 bbl/day average production requirement makes this project much larger in terms of the resource target, number of wells, CO2 required, etc.

A graphic portrayal of a hypothetical decline curve for a typical CO_2 EOR project is illustrated in Figure IV-14.

Almost all of the CO_2 utilized at an EOR project will ultimately be sequestered, as long as the operator separates and re-injects the CO_2 making it back to the production wellhead. Toward the end of a project, the CO_2-to-oil production ratio may become very large, making it difficult to reinject all of the CO_2 that is being produced. If this happens and if there is not an alternate project or storage facility to which the gas can be transported, some of it may have to be vented (or flared if there are combustible gases in it). The amount of “lost” CO_2 should be almost negligible, however, in comparison to the amount stored permanently.

[1]A somewhat more constant input of fresh CO_2 is possible and perhaps likely, based on contractual terms.

Figure IV-13



Pricing Notes

The current cost to purchase CO_2 at the Denver Hub is about $1.50 per MCF. Backing out pipeline transport fees, this translates to $1.25+ per MCF at the source flange. Dakota Gasification Company reports that they are selling large quantities of CO_2 from their coal gasification plant in North Dakota to a Canadian oil company for $12 per ton, or about $0.70 per MCF. This represents the low end of the market. The cost for EOR operators to recycle CO_2 from production wells is estimated to range from $0.25 to $0.30 per MCF. In order to best insure that CO_2 is recycled and ultimately stored/sequestered, the seller should not offer the gas at less than the recycle cost.

Macroeconomic EOR Cost Assumptions

Table IV-6 gives the CO_2 EOR project cost estimates that were used as a guideline for the macroeconomic projections in this study.

Table IV-6
Typical CO_2-EOR Per Barrel Costs

Cost Element	Range	1st project	Nth	Comments & Assumptions
Misc & OH	$4 – 5	$4.0	$4.0	More, bigger projects => minimum OH & misc
Taxes	$2 – 4	$4.0	$4.0	Starts high, stays constant assuming tax breaks, otherwise will rise
O&M Cost	$2 – 3	$3.0	$3.0	Sequestration will require maximum attention.
Electricity & Fuel	$1 – 3	$3.0	$3.0	Assumes mostly electricity, also high fuel costs
CO_2	$4 – 5	$4.0	$2.0	Assumes Denver City, TX, and/or CO2 recycle price initially
Royalty	$2 – 4	$7.5	$7.5	Assumes $50-$60/bbl crude oil price
Capital	$3 – 4	$3.5	$4.2	Assume average, increasing later due to more difficult targets

Source: Adapted from Oxy-Permian presentation to Texas Energy Planning Commission, April 27, 2004; see http://www.rrc.state.tx.us/tepc/CO2Texas4-27-04v6.pdf

The Capital and O&M costs in Table IV-6 are based on a presentation by Oxy-Permian to the Texas Energy Planning Commission, April 27, 2004. In the presentation, they gave a range of costs associated with CO_2-EOR projects. The costs were presented in terms of $/bbl of oil, and the figures in the table above are based on average projects of 20,000,000 barrels. Actual project sizes will vary greatly, but production figures published by *Oil and Gas Journal* (2006) are consistent with projects of this size. (Average production rate per project = about 3000 bbls/day.). Note that the "O&M" costs as shown in the above table include all non-capital costs.

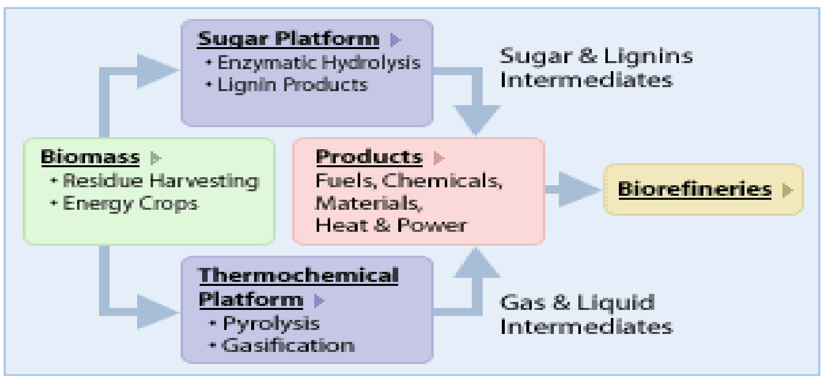
There are not likely to be significant cost savings in the reworking, recompletion, or redrilling of the field as a result of technological improvements, as these are relatively low-tech operations. The major changes will be in gradually shifting toward deeper and more difficult reservoirs that will cause capital costs to increase.

The primary reason that O&M costs may decline relates to the presumed decrease in the price of CO_2. This is anticipated to result as alternative liquid fuels facilities come on line in mass, and facility operators desire to generate some revenues for their CO_2 while at the same time sequestering the captured gas. Other costs can be expected to stay about the same. No additions were made for any monitoring costs that might be required for sequestration.

IV.E. Biomass

Liquid fuels are complex mixtures of hydrocarbons or oxygenated hydrocarbons in the form of ethers or alcohols. To transform biomass into these types of compounds the objective is to chemically manipulate the carbon, hydrogen, and oxygen in spite of the variable nature of the starting substrate. This typically involves breaking down the macropolymers of biomass into elemental molecules and then reconfiguring these molecules into the desired fuel compounds. DOE's Office of Energy Efficiency and Renewable Energy has supported R&D in the field of biomass to fuels for more than 25 years and has identified two fundamental approaches in a carrying out this transformation: One is a bioconversion process and the other uses thermochemical methods, as shown in Figure IV-14.

Figure IV-14: Biomass Conversion Approaches



Bioconversion primarily produces ethanol by fermenting sugars from the cellulosic and hemicellulosic components of biomass. The thermochemical pathway can produce either hydrocarbons or ethanol depending on the selected technologies employed. Each of these paths is discussed in more detail below.

IV.E.1. Biochemical Conversion

The basic biochemical conversion process is shown in Figure IV-15. This approach involves the initial breakdown (pre-hydrolysis) of the polymeric sugars cellulose and hemicellulose by exposure to dilute or concentrated acid. This step is followed by an enzymatic hydrolysis step where the enzymes selectively reduce the polymers and oligomers to C-5 and C-6 sugars. In the early stages of development the sugar streams were subsequently fermented using well-established yeast cultures. However, development of advanced strains of enzymes and fermentation microorganisms have enabled these two steps to be carried out simultaneously, thus reducing the capital and operating costs. Following the fermentation step, broth is sent to the recovery section of the process where conventional distillation and molecular sieve polishing separates the ethanol from the water and residual solids.

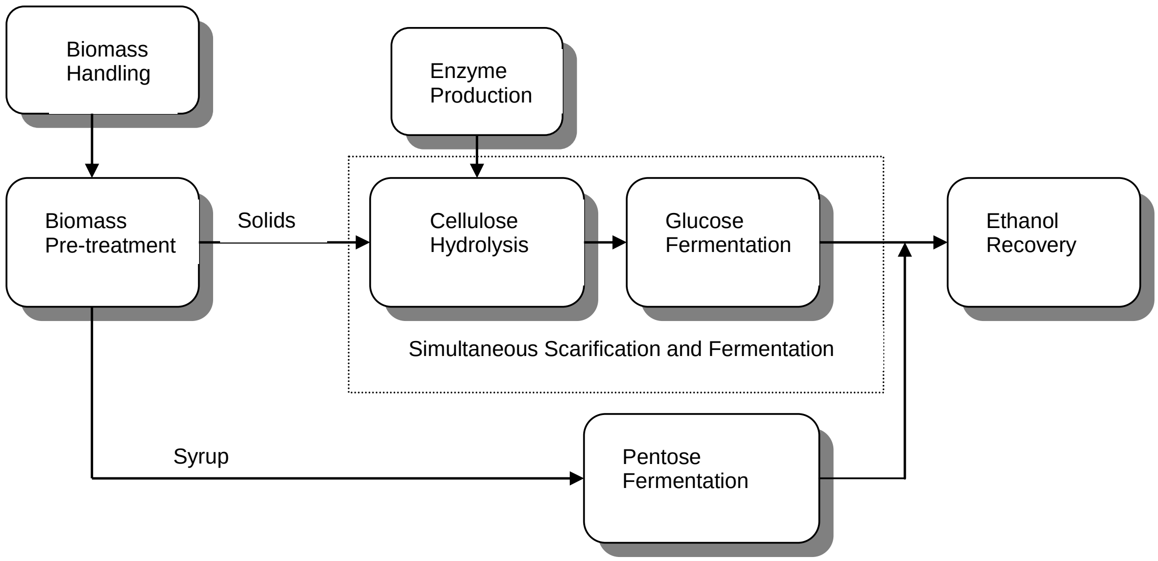


Figure IV-15: Process Diagram for Bioconversion of Lignocellulosic Biomass

A number of technical challenges remain to be addressed with this approach before the process can be considered economically viable:

- The hydrolysis of cellulose and hemicellulose occur at different rates, and overreaction during the pre-hydrolysis stage can result in production of undesirable compounds that have a deleterious effect on the microorganisms used in subsequent processing steps.
- The C-5 and C-6 sugars do not lend themselves to being effectively fermented by the same microorganisms. The pentose sugars are particularly difficult to ferment, although some advances have been reported in this area.[1]
- The product ethanol is an inhibitor to the fermenting microorganisms at relatively low levels (beyond five percent).
- The fermentation times are relatively long (up to five days), although some newer strains have been reported that carry out the fermentation in two days.

Most of the R&D effort is focused on addressing these technical challenges and a number of companies are venturing into the production of ethanol from Lignocellulosics using the basic process described above but with technical improvements they have developed. These U.S. companies include:

[1]A. K. Evans, Y.C. Chou, and M. Zhang, "Cofermentation of Glucose, Xylose, and Arabinose by Genomic DNA-Integrated Xylose/Arabinose Fermenting Strain of Zymomonas mobilis AX101", Mohagheghi, *Applied Biochemistry and Biotechnology*; issue 0273-2289, pp. 885-898.

- Abengoa currently has starch based ethanol plants and is planning on integrating the lignocellulosic component into its technology. It is planning to construct a 200 million liter fuel bioethanol plant in Spain in 2006 by combining a traditional cereals process with a lignocellulosic process. The former uses barley grain as its feedstock, while the latter uses the remainder of the barley plant -- husk and straw -- as the primary feedstock. The application of the lignocellulosic materials as well as the enzymes to convert them will be the subject of intense R&D.
- Logen recently announced a joint venture with Volkswagen and Shell that will assess the economic feasibility of producing cellulose ethanol in Germany. Logen's cellulose ethanol is a fully renewable advanced biofuel made from the non-food portion of agriculture residue such as cereal straws and corn stover, and its cellulose ethanol technology is the result of 25 years of R&D. It operates the world's only cellulose ethanol demonstration-scale facility and made the first commercial shipments of this fuel in April 2004.
- Arkenol is also pursuing lignolocellulosic biomass conversion and already has plants producing other products from acid hydrolysis of biomass.
- Bioengineering Resources, Inc. produces ethanol from biomass feedstocks but uses a different approach than that described above. Instead of breaking down the polymeric sugars with acid pre-treatment and enzymes, it employs gasification of the biomass followed by fermentation of the resulting producer gas. The company has a pilot facility that has been in operation for four years, and over the last two years it has continuously fed synthesis gas into the fermentation reactor without any measurable loss of activity by the patented microorganism.

Other than Bioengineering Resources Inc, which uses gasification to breakdown the lignocellulosic biomass, the bioconversion processes described above cannot utilize the lignin component for production of ethanol. This material will instead be used as a fuel to provide heat and power for efficient operation of the plant. In advanced integrated biorefineries this material will be used as a feedstock for thermochemical processes that are capable of converting it to additional liquid fuel.

IV.E.2. Thermochemical Conversion

Thermochemical technologies use heat instead of chemicals and enzymes to break down the complex polymeric structure of lignocellulosics. This technical approach for conversion of biomass falls under two primary categories: Pyrolysis and gasification. Pyrolysis is actually the first step in the gasification process, but each is discussed here as a separate process.

Biomass Pyrolysis

Pyrolysis is the application of heat to a material in the absence of oxygen, and the heat essentially breaks the chemical bonds of the targeted substrate, in this case biomass. The principal technical requirement is imparting a very high heating rate with a corresponding high heat flux to the biomass.[1] When exposed to this environment thermal energy cleaves the chemical bonds of the original macro-polymeric cellulose, hemicellulose, and lignin to produce mostly oxygenated molecular fragments of the starting biomass. These fragments have molecular weights (MW) ranging from a low of 2 (for hydrogen) up to 300-400. The lower MW compounds remain as permanent gases at ambient temperature while the majority of compounds condense to collectively make up what is called bio-oil at yields up to 70 wt%. This 70 wt% also includes the water formed during pyrolysis in addition to moisture in the biomass feed that ends up as water in bio-oil. The yield of permanent gas is typically 10-15 wt%, with the balance of the weight produced as char.[2]

Several reactor designs have been explored that are capable of achieving the heat transfer requirements, including fluidized beds (bubbling and circulating), ablative (in which the biomass particle moves across hot surface like butter on a hot skillet), vacuum, and transported beds without a carrier gas. Of these designs, the fluidized and transported beds appear to have gained acceptance as the designs of choice for being reliable thermal reaction devices capable of producing bio-oil in high yields.

Current pyrolysis systems are relatively small from a process industries throughput standpoint, as illustrated in Table IV-7. Some of the mobile systems that are currently under development or were demonstrated in the late 1980s have capacities of about five tons/day, which is similar to some of stationary units noted below. While biomass pyrolysis systems can be sized for mobile service, there are operations issues that will be more difficult to address in a "distributed" plant than a stationary one having access to standard utilities. Environmental risks may also be greater with hundreds of distributed units in the field compared to one or two central plants, and stabilization of

---

[1] T.B. Reed, J.P Diebold, and R. Desrosiers, "Perspectives in Heat Transfer Requirements and Mechanisms for Fast Pyrolysis," *Specialists Workshop on Fast Pyrolysis of Biomass, Proceedings*: *October 19-22*, 1980, Copper Mountain, Colorado, SERI/CP-622-1096, Solar Energy Research Institute, Golden, Colorado, pp. 7-20.

[2] A.V. Bridgewater, S. Czernik, and J. Piskorz, "An Overview of Fast Pyrolysis," *In: Progress in Thermochemical Biomass Conversion*, A.V. Bridgewater, Ed., Blackwell Science, Oxford, 2001, pp. 977-997.

the raw bio-oil may also be more difficult in a portable unit than at a central plant. These technical issues are being addressed by the research community. To a large extent, the question of which approach makes the most sense is tied to what the desired end products are and the regional access to the biomass resource.

Table IV-7
Worldwide Pyrolysis Plants

Reactor Design	Capacity	Organization or Company	Products
	Dry Biomass Feed		
Fluidized bed	400 kg/hr (11 tons/day)	DynaMotive, Canada	Fuel
	250 kg/hr (6.6 tons/day)	Wellman, UK	Fuel
	20 kg/ hr (0.5 tons/day)	RTI, Canada	Research/Fuels
Circulating Fluidized Bed	1500 kg/hr (40 tons/day)	Red Arrow, WI Ensyn design	Food flavorings/ chemicals
	1700 kg/hr (45 tons/day)	Red Arrow, WI Ensyn design	Food flavorings/ chemicals
	20 kg/hr (0.5 tons/day)	VTT, Finland Ensyn design	Research/ Fuels
Transported Bed	570 kg/hr (15 tons/day)	Renewable Oil International, AL	Research/Fuels
Rotating Cone	200 kg/hr (5.3 tons/day)	BTG, Netherlands	Research/Fuels
Vacuum	3500 kg/hr (93 tons/day)	Pyrovac, Canada	Pilot scale demonstration/ Fuels
Other Types	350 kg/hr (9.3 tons/day)	Fortum, Finland	Research/ Fuels

This technology is still in its early development stages from a standpoint of its commercialization status. The Red Arrow plants can be considered commercial, but they are focused on high value flavoring compounds that have limited markets. Large-scale systems to serve energy markets have not yet achieved commercial status.

A number of applications for bio-oil have been explored during the last 20 years, including substitutes for petroleum based fuels and extraction of useful chemical compounds. The use as petroleum fuel substitutes has not found widespread interest because the chemical properties are dramatically different than petroleum based hydrocarbons. This is principally because of the high oxygen content of the collective compounds comprising bio-oil.

Hydrotreating offers one approach for the effective removal of the oxygen in bio-oil. This is a petroleum refining operation that is used to remove unwanted elements such as nitrogen, sulfur, oxygen, and halides from petroleum crude oil.[1] Some success in using this approach to upgrading bio-oil was reported by Elliot et.al. in work done at Pacific Northwest Laboratory in the mid 1990's.[2] In a similar study using vegetable oils as the feedstock, a Canadian researcher successfully hydrotreated this substrate to produce a high quality diesel fuel. These studies show the potential of this approach to upgrade bio-oil to higher value hydrocarbons.[3] Companies such as Dynamotive and Renewable Oil International have plant designs for 100 ton/day systems that could potentially be fielded as satellite plants strategically located to minimize biomass transportation costs. These facilities could be coupled with hydrotreating and hydrocracking facilities as mini-distributed biorefineries to replace forest products industries that have moved off shore. Hydrogen for use in these processes can be readily obtained by reforming a portion of the bio-oil, and researchers at NREL have demonstrated this technology for the DOE Hydrogen Program.[4] There is substantial potential for this model in much of the interior West and Southeastern parts of the U.S. that have large biomass resources and declining forest products industries.

Biomass Gasification

Gasification of biomass and other carbonaceous materials has a long history dating back to the mid 1800s. It went out of favor when inexpensive petroleum resources became widely available, but since the Arab oil embargo of 1973 there has been increased interest in developing gasifier technology. The process is well understood and involves a number of sequential steps as heat and sub-stoichiometric amounts of oxygen are introduced to the biomass. These steps involve dehydration followed by pyrolysis with subsequent partial oxidation of the pyrolysis vapors. The heat released in this step facilitates the additional endothermic reactions to complete the conversion of the volatile compounds and char to a gaseous product consisting primarily of carbon monoxide and hydrogen. Depending on how the oxygen is provided to the gasifier, the following chemical reactions apply:

Partial combustion with air:

$$C_6H_{10}O_5 + O_2 + 3.76\ N_2 \longrightarrow 5CO + CO_2 + 5H_2 + 3.76N_2$$

---

[1]J.H. Gary and G.E. Handwerk, *Petroleum Refining Technology and Economics*, Volume 5, Marcel Dekker, Inc., 1975.
[2]D.C. Elliott and G. G. Neuenschwander, "Liquid Fuels by Low-Severty Hydrotreating of Biocrude," *Developments in Thermochemical Biomass Conversion*, Vol. 1, pp. 611-621, in A.V. Bridgwater and D. G.B.Boocock, eds., Blackie Academic & Professional, London: 1996.
[3]www.nrcan.gc.ca/se/etb/cetc/cetc01/htmldocs/Publications/factsheet_supercetane_technology_e.htm.
[4]www.hydrogen.energy.gov/pdfs/progress05/iv_a_13_evans.pdf.

Partial combustion with purified O2:

$$C_6H_{10}O_5 + O_2 \longrightarrow 5CO + CO_2 + 5H_2$$

Because of the high reactivity of the volatile compounds released during pyrolysis and the higher reactivity of biomass chars, gasification of biomass can also be carried out without the use of oxygen. In this process the biomass first undergoes pyrolysis at a moderate temperature in the range of 500° -600°C, and the vapors and char generated during this step are then transported to a reforming zone where temperatures above 800°C are maintained. This process is represented by:

Pyrolysis/steam gasification:

$$C_6H_{10}O_5 + H_2O \longrightarrow 6CO + 6H_2$$

The advantage of this method of gasification is that it can produce synthesis gas without the need for an expensive oxygen plant. Although not shown in these reaction equations, there are small amounts of tars, ammonia, and sulfur and chlorine compounds formed in the gasification process. Alkali metals can also be a problem, depending on the gasifier design and operating temperature, and all of these contaminants must be removed if chemical synthesis to liquid fuels is to be carried out. There are scrubbing technologies available for removing most of these compounds, but these are considered too expensive for the scale of operation considered appropriate for biomass gasification, typically less than 500 ton/day. Research on tar reforming catalysts is currently underway in Europe[1] and the U.S.[2] Gas cleanup to acceptable levels for catalytic conversion of synthesis gas continues to be the overarching challenge for biomass gasification to liquid fuels production, and examples of the level of contaminants required for Fischer-Tropsch synthesis are given in Table IV-8.

Very little has been reported in the literature on the effects of impurities on catalyst performance for ethanol synthesis or mixed alcohol synthesis, but one can make a reasonable assumption that the levels are similar to those shown in the above table. If gas cleanup technologies advance to the point of meeting the requirements shown above, the liquid fuels of choice would most likely be alcohols or Fischer-Tropsch hydrocarbons because of the favorable markets.

---

[1] P. María, et.al., "Commercial Steam Reforming Catalysts To Improve Biomass Gasification with Steam-Oxygen Mixtures. 2. Catalytic Tar Removal," *Ind. Eng. Chem. Res*., 37 (7), 2668 -2680, 1998.
[2] www.nrel.gov/docs/fy03osti/32815.pdf.

Table IV-8
Required Removal Levels for Fischer-Tropsch Feed Gas

Impurity	Removal Level
$H_2S + COS + CS_2$	< 1ppmV
NH_3 + HCN	< 1ppmV
HCl + HBr + HF	< 10 ppbV
Alkaline metals	< 10 ppbV
Soot, dust, ash	essentially completely
Organic compounds (tars)	below dew point

Source: H. Boerrigter, H. Uil Den, and H.P. Calis, "Green Diesel from Biomass via Fischer-Tropsch Synthesis: New Insights in Gas Cleaning and Process Design," *Pyrolysis and Gasification of Biomass and Waste, Expert Meeting, Proceedings*, Strasbourg, France, 30 September - 1 Oct, 2002.

A number of gasifier designs for effective gasification of biomass are currently under development for production of synthesis gas (without nitrogen). These include entrained flow, indirectly heated transport bed (Battelle design), oxygen fed fluidized bed, and two stage systems employing pyrolysis followed by steam reforming. The two stage designs are attracting considerable interest because of their relative simplicity and lack of requiring an auxiliary oxygen plant. CHOREN Industries has attracted Royal Dutch Shell and Daimler–Chrysler as partners based on the performance of its pilot plant that has been in operation since 2004.[1] The design of this system would be the most amenable for co-processing biomass with coal, and the system can be sized to be compatible with moderate scale FT gas to liquids plants currently being deployed to exploit stranded natural gas. This type of plant was installed in Nikiski, Alaska in 2002.[2]

Detailed specification of the biomass parameter estimates used in this study is given in Appendix G.

[1] www.choren.com/en/biomass_to_energy/carbo-v_technology/
[2] M. Ashley, T. Gamlin, and J.F. Freide, "The Ultimate Clean Fuel -- Gas to Liquid Products", *Hydrocarbon Processing*, February 2003.

IV.F. Transportation Energy Efficiency and Conservation

IV.F.1. Technologies Available For Increasing Vehicle Fuel Efficiency

The National Research Council (NRC) of the National Academies of Science conducted a landmark study that assessed the technologies available for improving vehicle fuel efficiency and their associated costs.[1] The NRC found that the technologies are continually evolving, and those currently available can be utilized more widely and efficiently and further refined to achieve enhanced fuel economy. In addition, emerging technologies, now in the late stages of development, will likely be introduced over the next several years and will be increasingly utilized, and advanced technologies currently in the R&D stage could become available over the next ten to 15 years.[2] The technical options for improving vehicle efficiency can be classified into two basic categories:

- Powertrain technologies, which include engines, transmissions, and the integrated starter-generator
- Load reduction technologies, which include mass reduction, streamlining, tire efficiency, and accessory improvements

These technologies and their associated costs and potential fuel efficiency improvements are summarized in Table IV-9. According to the NRC, these engine, transmission, and vehicle technologies are likely to be available within the next 15 years:[3] Some (listed as "production intent") are already available, are well known to manufacturers and their suppliers, and could be incorporated in vehicles once a decision is made to use them; others (designated "emerging") are generally beyond the R&D phase and are under development, and are sufficiently well understood that they should be available within 10 to 15 years. [4]

---

[1]National Research Council, National Academy of Sciences. *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*. Washington, D.C.: National Academy Press, 2002.

[2]A more complete discussion of these technical issues can be found in National Research Council, op. cit.; National Research Council, *Automotive Fuel Economy: How Far Should We Go?* Washington, D.C.: National Academy Press, 1992; John DeCicco and Marc Ross, "Improving Automotive Efficiency," *Scientific American*, December 1994, pp. 52-57; U.S. Office of Technology Assessment, *Advanced Automotive Technology: Visions of a Super-Efficient Family Car*, OTA-ETI-638, September 1995; John DeCicco and Marc Ross, "Recent Advances in Automotive Technology and the Cost-Effectiveness of Fuel Economy Improvement," *Transportation Research*, Vol. 1., No 2 (1996), pp. 79-96; David Greene and John DeCicco, *Engineering-Economic Analyses of Automotive Fuel Economy Potential in the United States*, Oak Ridge National Laboratory, ORNL/TM-2000/26, February 2000; John DeCicco, Feng An, and Marc Ross, *Technical Options for Improving the Fuel Economy of U.S. Cars and Light Trucks by 2010-2015*, American Council for an Energy Efficient Economy, July 2001.

[3]National Research Council, National Academy of Sciences. *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*, op. cit.

[4]For each technology, the NRC identified its likely cost to the consumer and estimated the percentage improvement in fuel economy that it could achieve. All of the technologies come at a price, from as little as $8 for low-friction lubricants (a 1-percent improvement in fuel mileage) up to as much as $560 for a "camless engine" (an emerging technology that would save 5 to 10 percent in fuel mileage).

Table IV-9
Potential Increases in Fuel Economy and Related Price Increases

Technology	Potential Fuel Efficiency Improvement	Potential Average Retail Price Increases
Engine Technologies		
Production-Intent Engine Technologies		
Engine friction and other mechanical/hydrodynamnic loss reduction	1 percent - 5 percent	$35 - $140
Application of advanced, low friction lubricants	1 percent	8 – 11
Multi-valve, overhead camshaft valve trains	2 percent - 5 percent	105-140
Variable valve timing	2 percent - 3 percent	35-140
Variable valve lift and timing	1 percent - 2 percent	70-210
Cylinder deactivation	3 percent - 6 percent	112-252
Engine Accessory Improvement	1 percent - 2 percent	84-112
Engine downsizing and supercharging	5 percent - 7 percent	350-560
Emerging Engine Technologies		
Camless Valve Actuation	5 percent - 10 percent	280-560
Variable Compression Ratio	2 percent - 6 percent	210-490
Intake Valve Throttling	3 percent - 6 percent	210-420
Transmission Technologies		
Production-Intent Transmission Technologies		
Continuously Variable Transmission (CVT)	4 percent - 8 percent	140-350
Five Speed Automatic Transmission	2 percent - 3 percent	70-154
Emerging Transmission Technologies		
Automatic Shift/Manual Transmission	3 percent - 5 percent	70-280
Advanced Continuously Variable Transmission	0 percent - 2 percent	350-840
Automatic Transmission with Aggressive Shift Logic	1 percent - 3 percent	__ - 70
Six-Speed Automatic Transmission	1 percent - 2 percent	140-280
Vehicle Technologies		
Production-Intent Vehicle Technologies		
Aerodynamic drag reduction on vehicle designs	1 percent - 2 percent	__ - 140
Improved Rolling Resistance	1 percent - 1½ percent	14 – 56
Emerging Vehicle Technologies		
42 Volt Electrical System	1 percent - 2 percent	70 - 280
Integrated Starter/Generator (idle off-restart)	4 percent - 7 percent	210 - 350
Electric Power Steering	1.5 percent - 2.5 percent	105 - 150
Vehicle Weight Reduction (5 percent)	3 percent - 4 percent	$210 - $350

Source: National Research Council.

With the exception of fuel cells, the technologies summarized in Table IV-9 are all currently under production, product planning, or continued development, or they are the subject of future product introduction in Europe or Japan. The feasibility of production is therefore well known, as are the estimated production costs. However, within the competitive cost constraints of the U.S. market, only certain technologies are currently considered practical or cost effective for introduction into different vehicle classes.[1]

IV.F.2. Transportation Efficiency Technologies

In addition to the technologies summarized above, there are a number of other technologies and initiatives to improve related infrastructures and peripherals that can be used to reduce petroleum demand and to reduce the pollutants associated with use of petroleum-derived fuels. EIA uses the following vehicle categories in its assessment of alternative fuel vehicles:

- Conventional fuel capable (gasoline, diesel, bi-fuel, and flex-fuel), and hybrid (gasoline and diesel)
- Dedicated alternative fuel (CNG, LPG, methanol, and ethanol)
- Fuel cell (gasoline, methanol, and hydrogen)
- Electric battery powered (lead acid, nickel-metal hydride, lithium polymer).
- New power-source technology, including all electric vehicles (BEVs), hybrid electric vehicles (HEV OS -- non-plug-in), plug-in hybrids (PHEVs), and fuel cell vehicles (FCVs)

All electric vehicles (BEVs) were used in the late 1920s and early 1930s for delivery vans and passenger vehicles and were reconsidered in the 1990's by vehicle manufacturers as either low cost commuter vehicles or as company fleet vehicles. BEV acceleration, speed, and handling can be equivalent to conventional vehicles and BEVs have the additional advantages of no tailpipe emissions, low noise, greater fuel efficiency, and low operating costs. Their major drawback is the low driving range, which is typically 40-120 miles on a single charge. In addition, a large amount of space in the vehicle is required for the batteries, and the batteries are heavy and have to be replaced during the life of the vehicle.

Hybrid electric vehicles -- the non-plug-in versions, or HEV Os, are currently being supplied in auto, truck and SUV versions (or will be in 2007) by the major Japanese vehicle manufacturers Honda, Toyota, Lexus, and Nissan and by GMC and Ford. The EPA posted mpgs for HEV Os range from 25-60 MPG for city driving and 26-56 mpg for highway driving. Plug-in conversions of the HEV have claimed mileage in excess of 100 mpg and may provide sufficient additional range to allow commuting and typical city driving with minimal use of gasoline.

The EV technologies discussed above are applicable to commercial-use light trucks and vans. Technology improvements to medium and large freight trucks include improved aerodynamics of bumpers and underside air baffles and wheel well covers, low rolling resistant tires, improvements to transmissions including electronic controls and reduced friction, direct injection gasoline and diesel-electric hybrid power trains for

[1] At present, three manufactures, Ford, Honda, and Toyota, sell hybrid gasoline-electric vehicles in the U.S. market.

medium-sized trucks, reduced waste heat and thermal management, and weight reduction[1] -- see Table IV-10.

Table IV-10
Freight Truck Fuel Efficiency Technology Characteristics

	Fuel Economy Improvement (percent)		**Maximum Penetration (percent)**		**Introduction Year**		**Capital Cost (2001 dollars)**	
	Medium	Heavy	Medium	Heavy	Medium	Heavy	Medium	Heavy
Aero Dynamics: bumper, underside air baffles, wheel well covers	2.3	2.7	50	66	2005	2005	$280	$550
Low rolling resistance tires	3.6	2.3	50	40	2004	2005	$800	$1,500
Transmission: lock-up, electronic controls, reduced friction	1.8	1.8	100	100	2005	2005	$900	$1,000
Diesel Engine: hybrid electric powertrain	36.0	N/A	15	N/A	2010	N/A	$8,000	N/A
Reduce waste heat, thermal mgmt	N/A	9.0	N/A	35	N/A	2010	N/A	$2,000
Gasoline Engine:								
Direct injection	10.8	N/A	25	N/A	2008	N/A	$700	N/A
Weight Reduction	4.5	9.0	20	30	2007	2005	$2,000	$2,000
Diesel Emission NO_x non-thermal plasma catalyst	-1.5	-1.5	25	25	2006	2007	$1,200	$1,250
PM catalytic filter	-2.5	-1.5	95	95	2006	2006	$1,250	$1,500
HC/CO: oxidation catalyst	-0.5	-0.5	95	95	2002	2002	$200	$250
NO_X adsorbers	-3.0	-3.0	90	90	2006	2007	$2,000	$2,500

Source: U.S. Energy Information Administration, 2006.

Non-highway use transportation includes aircraft, trains, and buses, river, lake, and coastal marine vessels, ground, air, and sea military equipment, agriculture/construction vehicles, and pipelines. In 2003, the air, rail, and marine movers of passengers and freight accounted for 15 percent of total U.S. petroleum consumption.

[1]These technology enhancements will also reduce emissions. However, technologies primarily aimed at reducing emissions, such as catalysts, catalytic filters, and adsorbers, tend to have a negative impact on fuel efficiency.

Fuel efficiency technology improvements in aircraft include engine improvements from fine-tuning compressors and turbine designs, addition of a propfan ahead of the compressor, improved thermodynamics, improved airframe aerodynamics, and greater use of weight reducing materials. Improvements in fuel efficiency and emission levels can also be realized through improvements in the air transportation infrastructure, including better air traffic control systems which reduce the wait times associated with arrivals and departures, improved weather forecasting and routing, etc.

Fuel efficiency improvements in rail transportation systems are dependent on infrastructure improvements such as train control systems to allow trains to travel safely at higher speeds, GPS tracking to allow more frequent use of specific routes, remote sensing of track defects, reduced idling time of yard locomotives when assembling trains, etc. Improvements to rolling stock include increased use of weight reduction materials, high-output diesel engines which make it possible for one new locomotive to replace two older models and to increase fuel efficiency and reduce emissions, and reduced size of engines on locomotives used for yard work or short hauls where speed is not required.

Technologies used to improve fuel efficiency and reduce emissions of power sources for terrestrial vehicles are also applicable to commercial and recreational marine vessels used on intra-coastal, river, and lake waterways. For example, the capability to produce higher amounts of power with smaller generators will result in significant fuel savings and a reduction in noxious emissions, and fuel cell development could lead to environmentally friendly propulsion alternatives. As in rail systems, improved fuel efficiency depends significantly on enhancements to waterway infrastructures.

Various infrastructure and peripheral transportation technology initiatives are also feasible. For example:

- Hydrogen will require a new and extensive infrastructure, and the form in which it is delivered will depend on the sources from which it is produced and will include consideration of process and distribution technologies, operating cost, safety, and materials.
- Improved high-performance batteries are required to deliver an acceptable level of performance and will be needed to reduce energy consumption. The NiMH batteries for HEV 0s, PHEVs, BEVs and FCVs currently available have improved significantly and are delivering longer life, better performance, and increased durability.
- DOT mandates that truckers rest for 10 hours after driving for 11 hours, and truckers may park at one of the approximately 5,000 truck stops in the U.S. However, in doing so they idle their engines an average of six hours a day, or about 1,800 hours annually, and emit over 200 pounds of NO_X, close to 400 pounds of CO, and 20 tons of CO_2 during this rest time to provide their sleeper

compartments with air conditioning or heating or to run electrical appliances such as refrigerators and televisions. Truck stop electrification (TSE) allows truckers to "plug in" their vehicles to operate necessary systems without idling their engines. In addition to significantly reducing emissions, over 800 million gallons of diesel fuel per year could be saved if TSE systems were implemented nationwide.

- Efforts are being made to develop light weight, super hard, and other materials, such as coatings that are near frictionless and catalysts and lubricants for existing and new engines for highway vehicles, railroad locomotives, and aircraft. Efforts are also being made to reduce the weight of truck bodies, freight cars, air frames, and vessels.
- Incentive programs could be designed to encourage more efficient use of existing transportation systems, such as long-haul shipping by rail instead of trucks. According to DOT and the Association of American Railroads, “railroads are three times more fuel-efficient than trucks. If just ten percent of the freight moved by highway were diverted to rail, the nation could save as much as 200 million gallons of fuel each year.” This is equivalent to 80,000 bpd of crude oil.[1]
- In addition to on-board computers used to improve power source performance, computers are being increasingly used to aid in the design of improved power sources for vehicles, aircraft, and vessels and related infrastructure. Computer-assisted control of intake, firing, and exhaust timing mechanisms are being developed to improve fuel economy and overall performance of existing reciprocating and diesel engines while at the same time reducing harmful emissions.

Table IV.-11 shows the potential impacts of electric and fuel cell vehicles, Table IV-12 shows the potential impacts of technology efficiency improvements in medium and heaving trucking, and IV-13 shows the potential impacts of technology efficiency improvements in aircraft. These tables illustrate that the potential liquid fuels savings from implementing various technology efficiency improvements are substantial, although the actual savings will likely be considerably less than the maximum potential.

IV.F.3. Incorporation of Transportation Fuel Efficiency and Conservation

In this study we assumed that, coincident with the crash substitute fuels programs, transportation fuel efficiency will also increase substantially by 2030, and the generic gains likely from transportation efficiency and conservation reduce forecast overall U.S. petroleum requirements. Mass transit, rail, and light rail initiatives were also assumed to be part of the demand side program. Estimates of increased

[1] In addition, EPA estimates that for every ton-mile, a typical truck emits approximately three times as much oxides and particulates as a locomotive.

transportation fuel efficiency were included as reductions in projected liquid fuel requirements through 2030. It was assumed that these efficiency improvements will occur in all transportation modes (light duty vehicles, heavy trucks, off-road vehicles, airplanes, ships, etc.) and will be induced by both prices and technology.

Table IV-11
Potential Impacts of Electric and Fuel Cell Vehicles Through 2030

	2004	**2015**	**2030**
Petrolelum Used in Mbbls Total	20.76	23.53	27.57
By Automobile	9.6	10.63	12.59
Used for Gasoline[a]			
MPG	26.7	37.9	48
Miles/bbl	520	739	936
Projected Usage	9.6	9.4	9.3
Electric Vehicles			
Hybrids			
HEV O			
MPG[a]	41.8	53	63
Miles/bbl	815	1,033	1,230
Projected Usage[b]	NA[c]	9.3	9.2
PHEV[c]			
MPG	>100	>100	>100
Miles/bbl	1,950	1,950	1,950
Projected Usage[d]	NA	8.7	8.4
All Electric			
MPG	>100	>100	>100
Miles/bbl	1,950	950	1,950
Projected Usage[e]	NA	8.7	8.4
Fuel Cell			
MPG	NA	NA	NA
Miles/bbl	NA	NA	NA
Projected Usage[f]	NA	8.5	4.6

[a]1.5 percent Improvement 2004-2015, 1 percent 2015-2030
[b]50 percent in use by 2015, 100 percent by 2030
[c]NA: Not applicable
[d]30 percent in use by 2015, 50 percent in use by 2030, >100 MPG
[e]Same as PHEV
[f]10 percent in use by 2015, 50 percent in use by 2030

Source: U.S. Energy Information Administration, 2006.

Operationally, the benefits from increased transportation fuel efficiency can be represented as a reduction in future U.S. liquid fuel requirements – as illustrated in Figure IV-16. Transportation fuel efficiency gains are represented by the reduction in the slope of the top line forecasting future liquid fuels consumption, whereas the production of substitute liquid fuels could be represented by increases in U.S. liquid fuel production. Since U.S. liquid fuel imports are the difference between U.S. consumption and U.S. production, both increased transportation fuel conservation and efficiency and substitute fuel production will decrease U.S. oil imports.

We developed estimates of the gains likely from transportation fuel efficiency from independent studies that have been conducted by organizations such as EIA. For example, EIA projects that in 2030 under its reference case oil will be $57/bbl. (2004 dollars), and that under the high oil price case oil will be $96/bbl. (2004 dollars). EIA projects that this price differential could reduce 2030 transportation liquid fuels demand by about 1.8 MM bpd – about nine percent of forecast 2030 transportation liquid fuel consumption.[1]

Table IV-12
Potential Impacts of Fuel Efficiency Improvements in Medium and Heavy Trucking
(Fuel Savings in Millions of Barrels/day)[a]

	2004		**2015**		**2030**	
	Use	Saves	Use	Saves	Use	Saves
Reference Case	3.7		4.2		5.0	
Aero Dynamics	3.6		4.1	0.1	4.9	0.1
Low Resistance Tires	3.6		3.8	0.4	4.6	0.4
Transmission Improvements	3.6		4.1	0.1	4.9	0.1
Weight Reduction	3.6		3.9	0.3	4.3	0.7
All Improvements				0.9		1.3

[a]The improvement and penetration data for the medium and heavy trucks have been averaged and the introduction years used were 30 percent in 2015 and 100 percent in 2030.

Source: U.S. Energy Information Administration, 2006.

In addition to the AE0 2006 reference and high oil price and low oil price cases, EIA developed stand-alone cases using the Transportation Demand Module of NEMS to examine the effects of more rapid technology change and adoption. For the transportation sector, in the high technology case:

- The characteristics of light-duty conventional and alternative-fuel vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs.

[1]AEO 2006, op. cit.

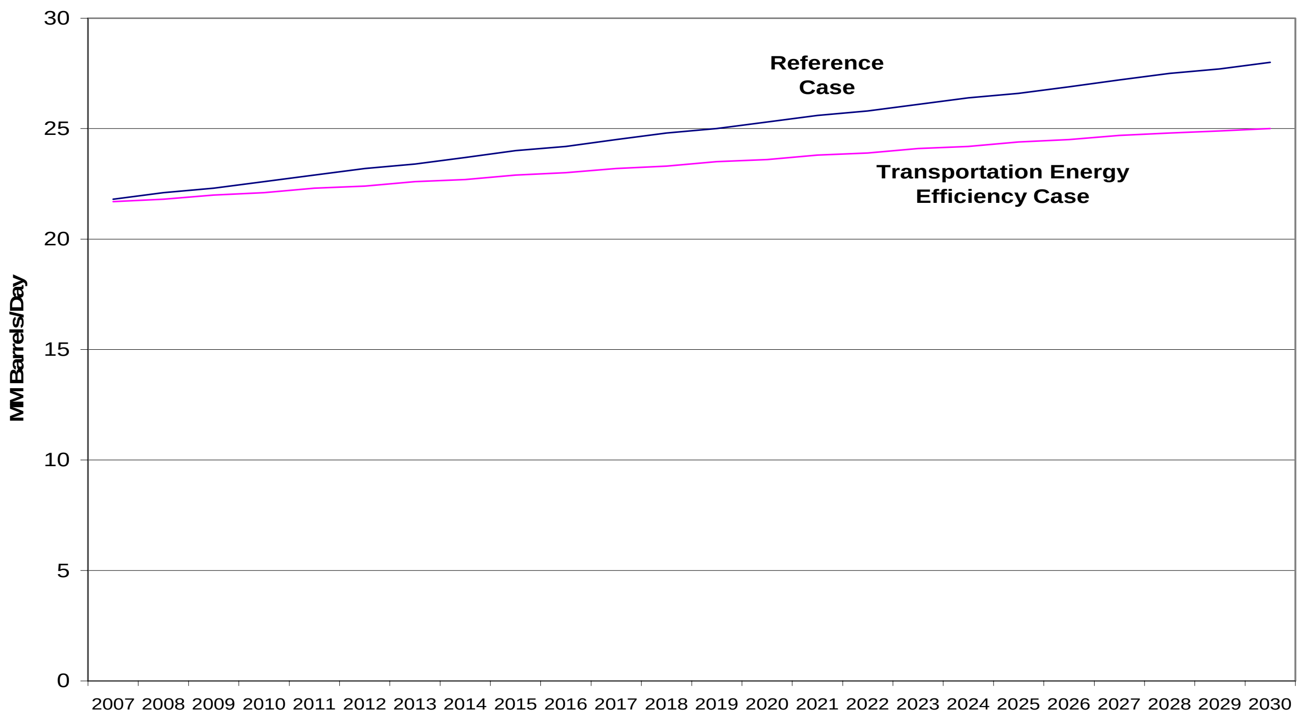
Table IV-13
Potential Impacts of Fuel Efficiency Improvements in Aircraft
(Fuel Savings in Millions of Barrels/day)

	2004		2015		2030	
	Use	Saves	Use	Saves	Use	Saves
Use by Aircraft in 2004	1.9		2.1	--	2.5	--
Engine Improvements						
Ultra-high Bypass[a]	1.9		2.1	0	2.1	0.4
Propfan[b]	1.9		2.0	0.1	2.2	0.3
Thermodynamics[c]	1.9		2.1	0	2.2	0.3
Aerodynamics						
Hybrid Laminar Flow[d]	1.9		1.9	0.2	2.5	0
Advanced Aerodynamics[b]	1.9		2.0	0.1	2.3	0.2
Weight Reducing Materials[b]	1.9		2.0	0	2.3	0.2
All Improvements				0.4		1.4

[a]Technology initiative implemented in 1995. [b]Technology initiative implemented in 2000.
[c]Technology initiative implemented in 2010. [d]Technology initiative implemented in 2020.

Source: U.S. Energy Information Administration, 2006.

Figure IV-16
Illustration of the Reduction in U.S. Liquid Fuel Requirements by Transportation Efficiency Initiatives



Source: Management Information Services, Inc., 2006.

- In the freight truck sector, the high technology case assumes more incremental improvement in fuel efficiency for engine and emissions control technologies.
- In the air travel sector, the high technology case reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight-reducing materials, providing a 25 percent improvement in new aircraft efficiency relative to the reference case in 2025.
- More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

EIA ran the high technology case with only the Transportation Demand Module rather than as fully integrated NEMS runs. Therefore, no potential macroeconomic feedback on travel demand was estimated, nor were changes in fuel prices incorporated. In the high technology case:

- Projected transportation energy demand in 2030 is seven percent (about 1.4 MM bpd) lower than in the reference case
- About 54 percent of the difference (0.750 MM bpd) is attributed to efficiency improvements in light duty vehicles as a result of increased penetration of advanced technologies, including variable valve lift, electrically driven power steering pumps, and advanced electronic transmission controls.
- Projected fuel use by heavy freight trucks in 2030 is about one percent lower in the high technology case than in the reference case
- Advanced aircraft technologies reduce fuel use for air travel by 24 percent in 2030.

The high tech case assumes lower costs and higher efficiencies for new transportation technologies. Advances in conventional technologies increase the average fuel economy of new light duty vehicles in 2030 from 29.2 miles per gallon in the reference case to 32.1 miles per gallon in the high technology case. The average efficiency of the light duty vehicle stock is 20.6 miles per gallon in 2010 and 24 miles per gallon in 2030 in the high technology case, compared with 20.4 miles per gallon in 2010 ant 22.5 miles per gallon in 2030 in the reference case.

For freight trucks, the average stock efficiency in the high technology case is 0.6 percent higher in 2010 and 1.1 percent higher in 2030 than in the reference case projection of 6.8 miles per gallon. Advanced aircraft technologies increase aircraft efficiency by 9.3 cent in 2010 and 31 percent in 2030 relative to the reference case projections.

Thus, EIA projects that[1]:

[1] Note that the two effects may not be additive.

- Price effects could reduce total transportation liquid fuel requirements in 2030 by about nine percent – 1.8 MM bpd.
- Technological advances could reduce total transportation liquid fuel requirements in 2030 by about seven percent – 1.4 MM bpd.

We also assessed the potential impact of increased market penetration of diesel and diesel hybrid vehicles. Vehicles with diesel engines typically get 20 to 40 percent more miles to the gallon than their gasoline counterparts, and the factors that make diesel engines more efficient include their operating unthrottled and their more efficient oxidizing of fuel.[1] Diesel engines also have a higher compression ratio, and diesel fuel has a higher energy density.

Diesel is the world's most efficient internal combustion engine. Because of this inherent efficiency, diesel is the predominant power source for many important sectors of the U.S. economy, including freight transport, public transportation, and off-road vehicles used in construction, agriculture, and mining. Diesel is also poised to help improve the fuel economy of American cars, pickups and SUVs, without requiring sacrifices in power and performance like some other fuel-efficiency alternatives. For example, the U.S. Department of Energy reports that if diesel vehicles reached a 30 percent market share by 2020, it would reduce U.S. oil consumption by 350,000 barrels a day. Four of the top ten most fuel-efficient vehicles for sale in the U.S. for the 2005 model year were diesel-powered, according to the U.S. EPA.

There is substantial potential for diesel-powered cars, pickups and SUVs in the United States. There are currently over 700,000 diesel powered light trucks manufactured in the North American market, and from 2000 to 2004, the percentage of light-duty diesels registered in the U.S. increased 56 percent. Diesel cars, trucks, and SUVs are expected to grow from three percent market share in 2004 to 7.5 percent by 2012, according to a recent study by JD Power and Associates. Globally, JD Power predicts that light duty diesels will reach a 26 percent market share within the next decade. In California, gradually increasing the use of currently available clean diesel technology in cars, pickups, and SUVs to levels now seen in Europe could save the state 110 million gallons of fuel per year by 2010 and up to 840 million gallons per year by 2030.

Diesel power dominates the modern luxury vehicle market in Europe, and across the continent diesel technology is synonymous with the highest standards of performance and reliability. Nearly half of all luxury cars purchased in Europe are powered by diesel engines. Europe's diesel emissions regulations have been designed to encourage the development of cleaner diesel engines and the use of ultra-low sulfur diesel (ULSD), while maintaining diesel's market viability. The well-developed track record of light-duty diesel in Europe stands as an example for American policy-makers amid current energy concerns.

---

[1]Diesel hybrid technology is already in use in large vehicles that transport heavy loads, including buses and locomotives, and General Motors subsidiary Allison Transmission produces hybrid diesel engines used by several municipal bus services.

New technology such as common-rail injection systems and particulate filters have given the current generation of diesels better performance than their gasoline-powered counterparts, while still retaining the fuel economy attributes associated with diesel engines. Diesel also has a number of environmental advantages over other types of internal combustion engines. Of the five major emissions from internal combustion engines -- carbon monoxide, hydrocarbons, carbon dioxide, particulate matter (PM), and nitrogen oxides (NO_x) -- diesel emits only small amounts of the first three, and the diesel industry has made great strides in reducing PM and NO_x emissions. In addition, the development of advanced emission technology has virtually eliminated the smoke and smell that were often associated with older diesels.

Engineers are pushing the envelope to improve diesel's efficiency even further. One example is the diesel hybrid electric bus. In head-to-head comparisons under laboratory conditions, diesel hybrid buses have demonstrated fuel economy improvements up to 60 percent better than conventional diesel or compressed natural gas (CNG). Most transit operators report real-world fuel economy improvements that range from 20 percent to 55 percent. For a typical urban transit bus that travels 40,000 miles per year, diesel hybrid technology will save approximately 1,500 gallons of fuel per year. A fleet of 1,000 city transit buses operating on diesel hybrid propulsion could save 1.5 million gallons of fuel per year.

Diesel and hybrid technologies have important synergies because hybrid systems reduce fuel consumption by relying on the electric motor while idling and during acceleration in stop-and-go traffic. Diesel engines are optimized for hauling heavy loads and for steady-speed highway driving, and the aspect that is critical in designing a diesel hybrid is to balance it for all operating environments. Hybrid gasoline-electric vehicles can obtain 20 to 40 percent better gas mileage than conventional gasoline engine vehicles, but diesel hybrid vehicles can achieve 20 to 30 percent better mpg than comparable gasoline hybrid vehicles. In addition to increasing fuel economy, coupling an electric motor with a diesel engine can help automakers meet increasingly stringent emissions standards. Thus, increased future market penetration of advanced diesel vehicles and diesel hybrid vehicles has the potential over the long run to greatly increase vehicle fuel efficiency and reduce U.S. liquid fuel requirements.

There are additional efficiency and environmental advantages to be realized through the large-scale integrating of coal-to-liquids, biomass-to-liquids, and oil shale-to-liquids diesel fuels into a U.S. diesel transition.

First, by producing environmentally superior transportation fuels from near-zero emissions plants, the United States can set an example for the world. Coal, biomass and oil shale derived liquid fuels produced from gasification and follow-up Fischer-Tropsch (FT) processing will produce ultra-clean, bio-degradable, essentially zero sulfur, low particulate, and NO_x emissions diesel and jet fuels, having performance characteristics superior to their conventional distillate counterparts. Zero sulfur gasoline also can also be produced. Increased performance from FT fuels translates to lower emissions per mile traveled, including CO_2.

In addition, one key factor in emission reductions is the conversion efficiency of any process relative to energy in vs. energy out. When compared to other processes, the FT process using a low temperature iron catalyst in a recycle configuration is nearly 60 percent efficient on an overall thermal balance, and this compares favorably with conventional power at 35 percent, combined cycle plants at 45 percent, and IGCC at 42 percent.

Accordingly, it thus appeared reasonable for this study to conservatively assume that transportation conservation and fuel efficiency could reduce U.S. liquid fuel requirements by about 3.0 MM bpd by 2030 and that these gains would stem from efficiency improvements in all transportation modes, including aircraft and heavy duty trucks, as well as in light duty vehicles.[1] The latter category will benefit from incremental improvements in existing technologies and also from new technologies, such as hybrids, advanced diesels, diesel hybrids, and electric power propulsion systems in hybrid, fuel cell, and battery-powered vehicles. In sum, transportation sector fuel efficiency gains of about 3.0 MM bpd by 2030 represent a reasonable, credible, and achievable goal.[2]

[1]This does not involve any explicit change in CAFE standards or enactment of new Federal government mandated fuel efficiency standards, but appropriate government incentives could facilitate some of these transportation fuel efficiency improvements.

[2]This estimate is consistent with estimates published in the literature; for example, see Roger H. Bezdek and Robert M. Wendling, "Fuel Efficiency and the Economy," *American Scientist*, Volume 93 (March-April 2005), pp. 132-139; and Roger H. Bezdek and Robert M. Wendling, "Potential Long-term Impacts of Changes in U.S. Vehicle Fuel Efficiency Standards." *Energy Policy*, Vol. 33, No. 3 (February 2005), pp. 407-419.

CHAPTER V
THE ECONOMICS OF ENERGY SECURITY AND INDEPENDENCE

The technologies and resources necessary to transform the U.S. energy future are well within reach. However, the potential for the United States to pursue a course of innovation and investment that will stimulate new industry and create good, high-wage jobs is not being realized, leaving the economy dangerously vulnerable to energy contingencies and price shocks that reduce economic growth and confront consumers with high and unpredictable fuel and utility bills. U.S. oil import dependence imposes an economic and security penalty of enormous proportions.

V.A. The Costs of Energy Insecurity and Dependence

The costs of achieving energy security and independence pale in comparison to the costs and risks the U.S. is incurring, and will incur, from the continuing and worsening U.S. energy insecurity and energy dependence. More specifically, the relevant question to ask is not "Can the U.S. afford to become energy secure and independent?" but, rather, "Can the U.S. afford *not* to become energy secure and independent?"

U.S. dependence on oil imports imposes a huge economic penalty that is not reflected in the retail price of gasoline. It is a penalty that costs jobs, drains investment capital, and increases the nation's defense burden, and it is a cost the U.S. cannot pay forever. Numerous analyses of these hidden costs have been conducted in recent years and the bottom line is that the economic penalty is enormous. There are at least three major elements that comprise this burden: Military expenditures specifically tied to defending Persian Gulf oil, the cost of lost employment and investment resulting from the diversion of financial resources, and the cost of the periodic "oil shocks" the nation has experienced – and will likely continue to experience. For example, these costs have been estimated to exceed $300 billion annually, and they are rising:

- Expenditures associated with defending the flow of Persian Gulf oil exceed $50 billion annually.[1]
- The loss of economic activity resulting from the diversion of financial resources is even larger. Direct economic losses are estimated at nearly $40 billion annually and indirect losses at $125 billion, for an annual total of more than $160 billion. This loss of economic activity results in a loss of 830,000 jobs in the U.S. and a loss of $15 billion in tax revenues and royalty payments to the federal, state and local governments.[2]

---

[1]The National Defense Council Foundation, "The Hidden Cost of Imported Oil," Washington, D.C., October 2003.
[2]Ibid.

- Oak Ridge National Laboratories estimates that the combined costs to the U.S. economy of the "oil shocks" over the past three decades total about $4 trillion.[1] Amortizing these costs over the past three decades yields an annual cost of nearly $85 billion.

Thus, the total economic costs to the U.S. exceed $300 billion per year.[2] When all of the elements are considered, they illustrate how expensive imported oil really is. When added to recent nominal prices for a barrel of imported oil, they raise its "real" price to well over $100 per barrel. This translates into a pump price for gasoline of over $5.00 per gallon – nearly $100 to fill an average gas tank. This economic toll that oil imports take on the U.S. economy can only be reduced by reducing and then eliminating oil imports. Thus, the realized and hidden costs of U.S. reliance on foreign oil are enormous, and when these costs are recognized the price for developing alternative energy sources appears far less expensive.

There are additional economic and related problems that result from excessive U.S. dependence on oil imports. These include the following:[3]

- Petroleum dominates the fuel market for vehicular transportation. This dominance substantially increases the difficulty of responding to oil price increases or disruptions in supply by substituting other fuels. Substituting other fuels for petroleum in the vehicle fleet as a whole has generally required major, time-consuming, and expensive infrastructure changes – infrastructure changes that would require decades and cost trillions of dollars.[4]
- The Middle East will continue to be the dominant petroleum producer for the foreseeable future and will have to meet a growing percentage of world oil demand – which is expected to increase by more than 50 per cent in the next two decades.
- The U.S. trade deficit creates the risk of major world economic disruption, but this could be substantially reduced by reducing oil imports.[5] The U.S. trade deficit exceeds $725 billion annually and

[1]See Paul L. Leiby, "Oil Use and U.S. Energy Security: Problems and Policy Responses," Oak Ridge National Laboratory, January 2002, and David L. Greene and Nataliya I. Tishchishyna, *Costs of Oil Dependence: A 2000 Update*, Oak Ridge National Laboratory, May 2000. These losses could be as high as $7.0 trillion when the past losses are estimated at their present value using a 4.5% discount rate.
[2]In addition, it has been estimated that OPEC's cartel power to keep oil prices above competitive levels has cost the U.S. economy between $5 trillion and $15 trillion over the past 30 years – see Amory B. Lovins, "U.S. Energy Security Facts," Rocky Mountain Institute, June 2003.
[3]See "Energy Independence," testimony of the Honorable R. James Woolsey before the U.S. Senate Committee on Energy, March 7, 2006.
[4]See Roger Bezdek, Robert Wendling, and Robert Hirsch, *Economic Impacts of U.S. Liquid Fuel Mitigation Options*, report prepared for the U.S. Department of Energy, National Energy Technology Laboratory, July 2006.
[5]For every billion dollars of the $250 billion oil trade deficit spent domestically in the U.S. to produce alternative fuels, it has been estimated that between 10,000 and 20,000 American jobs could be created. See Richard G. Lugar and R. James Woolsey, "The New Petroleum," *Foreign Affairs*, Vol. 78, No. 1 (January/February 1999).

the nation must borrow from the world's financial markets to finance this deficit.[1] The single largest category of imports is the $250 billion a year borrowed to import oil – which could increase to $300 billion in 2006.[2] The accumulating debt increases the risk of a flight from the dollar and major increases in interest rates – both of which could have major negative economic consequences for both the U.S. and its trading partners.

- The petroleum infrastructure is highly vulnerable to terrorist attacks and natural disasters. Terrorist groups are well aware of U.S. dependence on imported oil and will exploit the vulnerability associated with it. It will be difficult for the U.S. to register progress in the war against terrorism while America's appetite for Middle Eastern oil grows, and continued dependency will invite terrorist attacks.[3] For example, a successful terrorist attack on the Saudi Abquaiq facility could take six million bpd off the market for a year or more, escalating petroleum to well over $100/barrel and severely damaging the U.S. – and the world -- economy. Further, U.S. refineries are concentrated along the hurricane-prone Gulf Coast, and the Trans-Alaska Pipeline is vulnerable to disruption.
- The possibility exists, both under some current regimes and among those that could come to power in the Middle East, of embargoes or other supply disruptions. Even under the most optimistic assumptions, there is substantial risk that for some time the region will be characterized by chaotic change and unpredictable governmental behavior.
- Wealth transfers from oil are used to fund terrorism and its ideological support.[4]

V.B. The Rationale for Energy Security and Independence

There seems to be two extremes in the debate over energy security and independence: "Pollyanna optimists" continue to insist that oil will remain abundant and cheap for the foreseeable future and that there is no need for initiatives to increase U.S. energy security and independence, while, at the other extreme, doomsday proponents contend that impending oil shortages portend the end of Western civilization and that

[1]See James K. Jackson, "U.S. Trade Deficit and the Impact of Rising Oil Prices," CRS Report for Congress, February 13, 2006.
[2]The U.S. currently spends more than $200,000 a minute on foreign oil imports.
[3]U.S. dependence on oil also makes it difficult to change the perception of the Arab and Muslim masses about America and its goals in the region. U.S. efforts in Iraq and elsewhere in the Middle East to promote democracy and freedom are seen as nothing more than a smokescreen to cover up for an agenda of exploitation of Arab oil. There is little that the U.S. government can do to change this perception as long dependence on Arab oil continues to set the agenda for Middle East policy.
[4]Estimates of the amount spent by the Saudis over the past three decades spreading Wahhabi beliefs throughout the world range up to $100 billion. Furthermore, some oil-rich families of the Middle East fund terrorist groups directly.

little can be done to avert it.[1] Still others contend that the problem is not that liquid fuel substitutes are not available, but that they are too expensive or impractical to support U.S. levels of economic productivity and living standards. Nevertheless, the actual situation is considerably different.

There is little doubt that there will be transition costs involved in pursuing U.S. energy security and independence, as there are in every major economic change. However the increasing U.S. reliance on foreign sources of energy will be incalculably more expensive than any plausible adaptation, and the transition costs involved are more properly viewed as necessary investments in the nation's energy future.[2] Further, the difficulties involved with developing meaningful energy alternatives are exaggerated.

To begin with, estimating the costs and benefits of conventional oil against alternative sources of substitute fuels is extremely complex, since many costs of fossil fuel use are easily externalized. As discussed above, the cost of potential oil shocks, military expenditures aimed at securing oil sources, and other "externalities" and the effects of imbedded subsidies obscure the real price of "cheap" oil.[3]

The economic advantages resulting from developing alternative energy technologies, while substantial, are not easily factored into such estimates. The tendency to underestimate the gains that alternatives can provide is frequently compounded by a tendency to stress costs more than benefits. In addition, the potential for a rapid changeover also tends to be underestimated, analysts forgetting that comparably large transformations have happened before in a relatively short period of time. For example, oil became cheaper than coal only in the mid-1950s. Nevertheless, coal went from generating 100 percent of Europe's thermal electricity to less than half by 1973, with oil replacing it even as total energy requirements increased substantially.[4]

Another problem with such estimates is their built-in assumption that the technology and economics of the alternatives will be static. However, the current costs of many technologies, including coal liquefaction, biomass, and oil shale, will likely decrease substantially as large numbers of production facilities are constructed and plant costs are reduced from first plant costs to "nth plant costs."[5]

---

[1] As examples of the former, see Leonardo Maugeri, "Oil: Never Cry Wolf – Why the Petroleum Age is Far From Over," *Science*, Vol. 304, May 21, 2004, pp. 1114-1115; Michael C. Lynch, "Closed Coffin: Ending the Debate on 'The End of Cheap Oil,' A Commentary," DRI/WEFA, September 2001. As examples of the latter see Paul Roberts, *The End of Oil*, Boston: Houghton Mifflin, 2004 and Richard Henberg, *The Party's Over*: Garbiola Island, Canada: New Society Publishers, 2003.
[2] See the discussion in Nader Elhefnawy, "Toward a Long-Range Energy Security Policy," *Parameters*, U.S. Army War College, February 24, 2006.
[3] However, the issue of energy subsidies is little understood and is often misused by proponents of specific energy technologies. See Roger H. Bezdek and Robert M. Wendling. "The U.S. Energy Subsidy Scorecard." *Issues in Science and Technology*, Volume XXII, No. 3 (Spring 2006), pp. 83-85.
[4] See Paul Bairoch, *Economics and World History*, Chicago: University. of Chicago Press, 1993, p. 62.
[5] These cost reductions are difficult to estimate, either as a function of technology, time, or number of plants, but they could approach a factor of three within a decade of program initiation; see Robert L. Hirsch and Roger H. Bezdek, "Estimation of Crash Program Cost Escalations," SAIC and MISI, April 2006.

A third problem is the tendency to view the matter as a choice between the outright replacement of the current energy regime, complete conversion to a specific alternative technology, or nothing at all. The reality, however, is that partial, incremental solutions can provide a cushion until a more complete transition can be achieved. Thus, the required alternative is not a stark choice between, for example, energy efficiency or coal liquefaction, or between oil shale or biomass. Rather, as demonstrated in this study, all available alternatives will be required.[1]

Further, the energy base of the future will have to be created using the existing energy base, just as the oil-based economy was built using previously existing sources. Substitute fuel technologies are available; what is really at issue is making appropriate and timely use of that potential.

Another important point is that the effects of future energy disruptions and constraints will not be uniform: Nations that have developed viable substitute fuel technologies and energy efficiency initiatives will be less affected than those which have not. In a comprehensive analysis of the vulnerability of the U.S. economy to oil shortages and price shocks, the Congressional Research Service concluded that if alternative non-petroleum energy sources could be developed on a large scale so they supply a large portion of U.S. energy needs, then the economy would be less sensitive to such perturbations.[2]

Conversely, failure to develop alternative energy options will likely expand the already massive U.S. trade deficit, rather than constituting a new opportunity for economic growth. Thus, failure to develop the alternatives will make it likely that oil shortages and price increases will harm the United States more severely than the other developed nations, weakening its international position relatively as well as absolutely.[3]

The current popularity of free trade and market-based economic ideology makes it easy to minimize the degree to which key economic and technological innovations and transformations have historically been supported by government. While it is the robber

---

[1]In reality, there are only three basic sources of energy: Solar in its various forms, nuclear, and fossil. Technology advancements involve more reliable and more efficient ways to utilize solar incidence, fossil resources and nuclear resources and recover and convert these resources into useful, end-use forms. In the end, the question of efficiency refers to how much wealth can be created for a given input of primary resource.

[2]See Mark Labonte, *Rising Oil Prices: What Dangers do They Pose for the Economy*? Congressional Research Service, January 2001, and Mark Labonte and Gail Makinen, *Energy Independence: Would it Free the United States From Oil Price Shocks*? Congressional Research Service, November 2000.

[3]Another likely ramification of future energy shortages is a new wave of debt crises and state failures. As in the 1970s, those most vulnerable would be the poorest nations dependent on oil imports, which will suffer greatly from oil shortages and high prices – see Robert Hirsch, Roger Bezdek, and Robert Wendling, *Peaking of World Oil Production: Impacts, Mitigation, and Risk Management*, report prepared for the U.S. Department of Energy, National Energy Technology Laboratory, February 2005, pp. 27-32. Some of these nations may degenerate to the point of collapse. As recent events have demonstrated, the U.S. cannot easily insulate itself from these problems, given the refuge for criminal activity and terrorism such areas will provide, as well as the waves of refugees they may generate. It may even be possible for radical ideologues to seize power in a major state -- see the discussion in Elhefnawy, op., cit.

barons who are celebrated, the railroads of the 19th century were built with massive government assistance in the form of loans, land grants, and other subsidies. In the 1950s, the U.S. did not expect the private sector to build a highway system by itself. Nuclear energy, electronics, commercial aviation, the Internet, space technology, medical research, computers, and biotechnology have all benefited greatly from massive government support.

Indeed, it is the legitimate function of government to act where a need exists and the private sector is either unwilling or unable to satisfy it. This is the case at present with the development of substitute liquid fuel technologies. Science and technology in the U.S. has been most successful when explicitly oriented toward a particular goal, as with the early space program. The Soviet launch of the first Sputnik satellite was a profound shock, but the U.S. responded effectively with massively enlarged investment in scientific education and research. The result is that the U.S. is currently in a dominant position in space, and its satellite networks are a cornerstone of unprecedented military superiority. Where energy is concerned, the "Sputnik moment" has long since arrived. Freeing the American economy from oil dependence arguably deserves at least the same priority the moon mission enjoyed 40 years ago, since it concerns a vital national interest.

The program proposed in the present study is ambitious, and it may be argued that despite the unease surrounding oil prices in excess of $70 a barrel, there is no "emergency" yet. The point, however, is to prevent the situation from ever becoming a dire emergency.

V.C. U.S. Energy Policy

U.S. energy policy traditionally aimed at an expansion of oil and gas production, while investing in nuclear energy. There was a brief period of greatly increased support for alternative energy technologies in the 1970s and early 1980s; however, the decline in oil prices in the 1980s and the ensuing preference for strictly market-based solutions quickly ended this, and federal government support for new and alternative energy was drastically reduced and in some cases terminated.[1] The nascent alternative energy industry was not only left to sink or swim among more mature competition, but as a net result of assorted tax policies and subsidies it was put at a disadvantage, and it withered.

Since price and allocation controls imposed in the 1970s were removed, U.S. energy policy has primarily relied on the market. The relatively unhindered forces of supply and demand are allowed to determine the prices of different energy sources and the public has been allowed to access any energy source for consumption. The rationale for this policy is that market prices best reflect the relative scarcity to society of

---

[1]For example, federal R&D for some alternative energy technologies declined by nearly 90 percent between 1981 and 1988. See Roger H. Bezdek and Robert M. Wendling, "Allocating Funds." *World Coal*, June 2006, pp. 1-6. Support for technologies such as oil shale was terminated.

the energy source in question. Reliance on the market as an energy policy is justified because it results in economically efficient decision-making.[1]

Nevertheless, this primary reliance on the market has not prevented the federal government from playing an active role. The government has sought to increase the supply of alternative fuels by promoting such petroleum substitutes as gasohol. It has also attempted to reduce the demand for energy by mandating fuel efficiency standards for motor vehicles and appliances, and by providing substantial subsidies to different energy technologies – primarily to the oil industry.[2]

Moreover, there are theoretical objections to a totally market-based national energy policy. They rest on the argument that while market prices may incorporate all the relevant costs to the individual, they may fail to incorporate those that are relevant to the nation. There may be environmental concerns that the market price does not capture. Market prices may also fail to incorporate a premium to help counteract any unacceptable foreign influence on U.S. foreign and domestic policies. For example, this reliance could affect national security in event of an armed conflict. Considerations such as these explain the existence of the Strategic Petroleum Reserve.

Relying solely on the private sector and market forces has worked for so long that policy-makers may not comprehend the government's appropriate role in an increasingly supply-constrained market. Relying solely on the private sector may not be viable because of the fiscal, access and regulatory impediments the private sector faces. There are numerous impediments to energy and technology development that may need to be mitigated by government policies – for example, access to resources and changing fiscal requirements to accommodate high capital costs. As energy development moves from conventional to unconventional resources it shifts from resources with steep decline curves (oil and gas) to those with different decline curves, such as solar and minable unconventional resources. This production profile has implications for business models, and the government should be aware of these changes and adjust tax and royalty policy to accommodate them.

Finally, since oil supply shocks are seldom anticipated, market prices can and do rise dramatically when they occur. When prices rise suddenly and sharply in the short run, they can be disruptive and, in the past, have had a measurable effect on GDP, employment, and inflation. More recently, as noted in Chapter I, in April 2006 the Federal Reserve Board determined that the increase in energy prices over the past three years had significantly reduced the purchasing power of households and decreased the profits of non-energy firms, thereby restraining both consumer spending and business investment.[3] The Fed estimates that these increases in energy prices have reduced real GDP growth nearly one percent per year over this period.

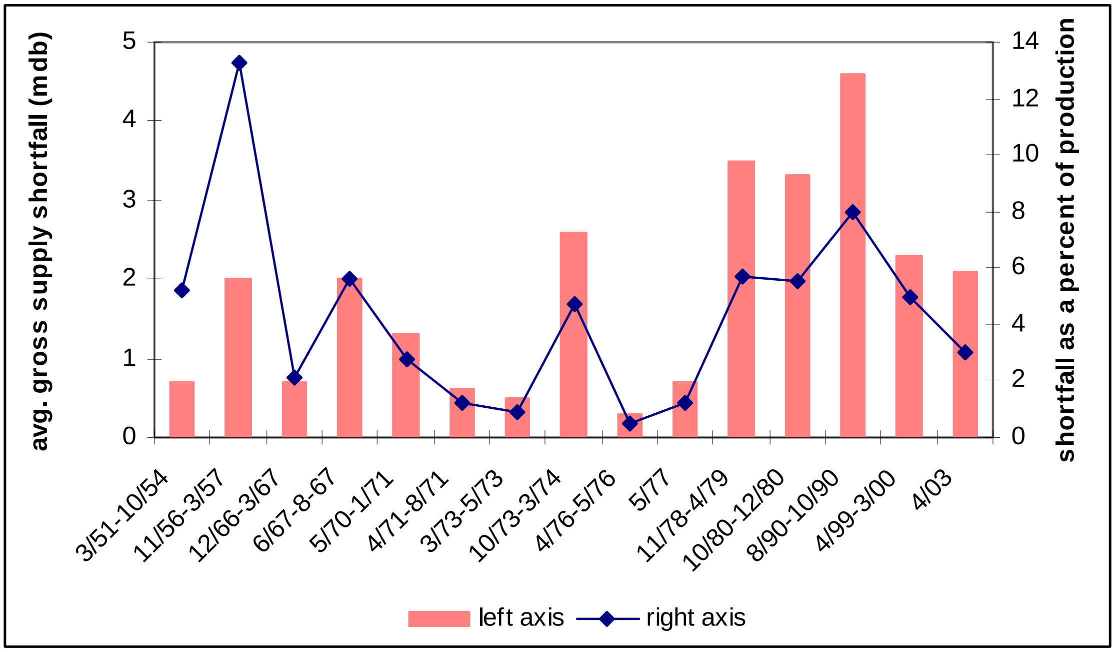
[1]See Mark Labonte, op. cit., and Mark Labonte and Gail Makinen, op. cit.
[2]Bezdek and Wendling in "The U.S. Energy Subsidy Scorecard," op. cit., estimated that through 2003, federal government energy subsidies totaled $644 billion (2003 dollars). Through 2005, in 2005 dollars, these subsidies likely totaled close to $700 billion. Nearly half of these subsidies were to the oil industry.
[3]"Letter from Federal Reserve Board Chairman Ben Bernanke to Representative J. Gresham Barrett," April 5, 2006.

V.D. The Record of U.S. Energy Insecurity

There have been over a dozen global oil supply disruptions over the past half-century,[1] as summarized in Figure V-1. Briefly:

- Disruptions ranged in duration from one to 44 months. Supply shortfalls were 0.3 - 4.6 MM bpd, and eight resulted in average gross supply shortfalls of at least 2 MM bpd.
- Percentage supply shortfalls varied from roughly one percent to nearly 14 percent of world production.
- The most traumatic disruption, 1973-74, was not the most severe, but it nevertheless lead to greatly increased oil prices and significant worldwide economic damage.
- The second most traumatic disruption, 1979, was also neither the longest nor the most severe.

Figure V-1
Global Oil Supply Disruptions: 1954-2003



Source: U.S. Energy Information Administration and Management Information Services, Inc., 2006

---

[1]U.S. Department of Energy, Energy Information Administration, "Latest Oil Supply Disruption Information," eia.doe.gov, 2004; U.S. Department of Energy, Energy Information Administration,. "World Oil Market and Oil Price Chronologies: 1970-2003," March 2004; U.S. Department of Energy, Energy Information Administration, "Global Oil Supply Disruptions Since 1951", 2001; U.S. Department of Energy, Energy Information Administration, *Annual Energy Review*, 2002;U.S. Department of Energy, Energy Information Administration, *International Petroleum Monthly*, April 2004.

Estimates of the damage caused by past oil price disruptions vary substantially, but without a doubt, the effects were significant. Economic growth decreased in most oil importing countries following the disruptions of 1973-74 and 1979-80, and the impact of the first oil shock was accentuated by inappropriate policy responses.[1] Despite a decline in the ratio of oil consumption to GDP in recent decades, oil remains vital and there is considerable empirical evidence regarding the effects of oil price shocks:

- The loss suffered by the OECD countries in the 1974/-75 recession amounted to $350 billion (current dollars) -- $1.1 trillion in 2003 dollars, although part of this loss was related to factors other than oil prices.[2]
- The loss resulting from the 1979 oil disruption was about three percent of GDP ($350 billion in current dollars) in 1980 rising to 4.25 percent ($570 billion) in 1981, and accounted for much of the decline in economic growth and the increase in inflation and unemployment in the OECD in 1981-82.[3]
- The effect of the 1990-91 oil price upsurge was more modest, because price increases were smaller and they did not persist.
- Although oil intensity and the share of oil in total imports have declined in recent years, OECD economies remain vulnerable to higher oil prices, because of the "life blood" nature of liquid fuel use.

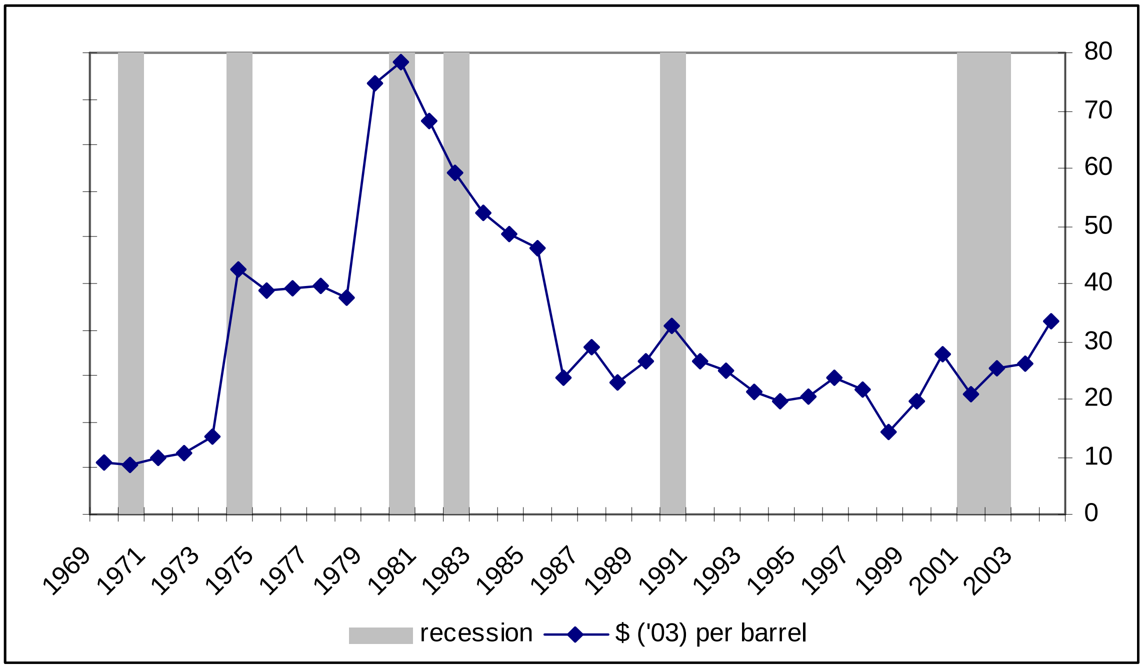
As illustrated in Figure V-2, oil price increases have preceded most U.S. recessions since 1969, and virtually every serious oil price shock was followed by a recession. Thus, while oil price spikes may not be necessary to trigger a recession in the U.S., they have proven to be sufficient over the past 30 years.

For the U.S., each 50 percent sustained increase in the price of oil will lower real U.S. GDP by about 0.5 percent, and a doubling of oil prices would reduce GDP by a full percentage point. Depending on the U.S. economic growth rate at the time, this could be a sufficient negative impact to drive the country into recession. If the shortfall persisted or worsened, the economic impacts would be much greater. As noted, oil supply disruptions over the past three decades have cost the U.S. economy about $4 trillion, so supply disruptions associated with increasing U.S. oil import dependence could cost the U.S. as much as all of the oil supply disruptions since the early 1970s combined.

---

[1]See Lee, Ni, and Ratti, op. cit., and J.D. Hamilton and A.M. Herrera "Oil Shocks and Aggregate Macroeconomic Behavior: The Role of Monetary Policy," *Journal of Money, Credit and Banking*, 2003.
[2]This totals about $1.1 trillion in 2003 dollars and was equivalent to a once-and-for-all reduction in real GDP of about seven percent; however, part of that loss was likely attributable to structural and cyclical economic factors unrelated to the oil-price shock. See Faith Bird, "Analysis of the Impact of High Oil Price on the Global Economy," International Energy Agency, 2003.
[3]These losses totaled about $700 billion and $1.1 trillion, respectively in 2003 dollars. Losses of this magnitude are significant and represent the difference between vibrant, growing economies and economies in deep recession. There is considerable debate as to precisely how much of these losses was attributable to the oil price shocks, to fiscal and monetary policies, and to other factors.

Figure V-2. Oil Prices and U.S. Recessions: 1969-2003



Source: U.S. Joint Economic Committee and Management Information Services, Inc., 2006.

The effects of oil shortages on the U.S. are also likely to be asymmetric. Oil supply disruptions and oil price increases reduce economic activity, but oil price declines have a less beneficial impact.[1] Oil shortfalls and price increases will cause larger responses in job destruction than job creation, and many more jobs may be lost in response to oil price increases than will be regained if oil prices were to decrease. These effects will be more pronounced as oil price volatility increases, and the repeated economic and job losses experienced during price spikes will not be replaced as prices decrease. As these cycles continue, the net economic and job losses will increase, and sectoral shifts will likely be pronounced. Even moderate oil disruptions could cause shifts among sectors and industries of ten percent or more of the labor force.[2] Continuing oil shortages will likely have disruptive inter-sectoral, inter-industry, and inter-regional effects, and the sectors that are (both directly and indirectly) oil-dependant will be severely impacted.[3]

---

[1]See Mark Hooker, "Are Oil Shocks Inflationary? Asymmetric and Nonlinear Specification Versus Changes In Regime," Federal Reserve Board, December 1999.

[2]Hillard Huntington, "Energy Disruptions, Interfirm Price Effects, and the Aggregate Economy," Energy Modeling Forum, Stanford University, September 2002; S.J. Davis, and J. Haltiwanger, "Sectoral Job Creation and Destruction Response to Oil Price Changes," *Journal of Monetary Economics,* Vol. 48, 2001, pp. 465-512.

[3]"Demand destruction" has often been identified as a solution, since oil price increases resulting from a disruption will reduce demand and this will moderate further price increases. However, demand is reduced because the economy is devastated and large numbers of jobs are lost. Demand destruction – a polite word for economic and job losses – is the problem, not the solution. See the discussion in Roger Bezdek and Robert Wendling, "The Case Against Gas Dependence," *Public Utilities Fortnightly*, Vol. 142, No. 4, April 2004, pp. 43-47.

Monetary policy is more effective in controlling the inflationary effects of a supply disruption than in averting related recessionary effects.[1] Thus, while appropriate monetary policy may be successful in lessening the inflationary impacts of oil price increases, it may do so at the cost of recession and increased unemployment. Monetary policies tend to be used to increase interest rates to control inflation, and it is the high interest rates that cause most of the economic damage. If U.S. oil import dependence is not reduced, devising appropriate offsetting fiscal, monetary, and energy policies will become more difficult. Absent the development of large scale substitute fuel programs, coming decades may resemble the "stagflation" of 1970s, only worse, with dramatic increases in inflation, long-term recession, high unemployment, and declining living standards.[2]

Since oil is an important input in the production and transport of most goods, an increase in the price of oil raises the cost of production for producers. What makes a supply shock so difficult for policymakers to respond to is the fact that it reduces economic output and raises the price level. Thus an argument exists, even in the context of a policy that places primary reliance on the market, for an energy strategy that may not be strictly market driven. In particular, as noted above, if alternative non-petroleum energy sources can be developed on a large scale so they could supply a significant portion of U.S. energy requirements, then the economy would be less sensitive to energy contingencies and oil price shocks.

[1]Joint Economic Committee of the U.S. Congress, "10 Facts About Oil Prices," March 2003; Mark Hooker, "Oil and the Macroeconomy Revisited," Federal Reserve Board, August 1999.

[2]During disruptions, public actions may be required to address societal risks. This creates a dilemma: In the event of a severe shortfall of long duration, government intervention of some sort may be required, and allocation plans to moderate the effects of this shortfall will likely be advocated. However, given the experience of the 1970s, many of the policies enacted in a crisis atmosphere will be, at best, sub-optimal. For example, in 1980, the Federal government developed a Congressionally-mandated stand-by U.S. gasoline rationing plan which could, in some form, be implemented; see *Standby Gasoline Rationing Plan*, U.S. Department of Energy, Washington, D.C., June 1980.

VI. THE ECONOMIC AND JOBS BENEFITS OF ENERGY SECURITYAND INDEPENDENCE

VI.A. Requirements to Achieve Liquid Fuels Security and Independence by 2030

In the base case (absent any substitute liquid fuels initiatives), in 2030 the U.S. will be consuming 27.6 MM bpd of liquid fuels, producing 10.4 MM bpd, and importing 17.2 MM bpd.[1] Therefore, the "import gap" that needs to be eliminated to achieve U.S. energy security and independence by 2030 is 17.2 MM bpd. Table VI-1 indicates how this will be achieved with the SSEB American Energy Security (AES) initiatives.

These contributions are based on a sustained maximum effort to achieve U.S. energy security and independence by 2030 – which is the basis of the study and represents a major shift in U.S. liquid fuel supply sources over the next two decades. The incremental contributions listed in Table VI-1 were derived by experts in each of the technology areas, as described in the preceding chapters.

Table VI-1
Incremental Contributions Required From Each Initiative to Achieve Energy Security and Independence in 2030

Initiative	MM Barrels/day Incremental Contribution Required in 2030[a]	Percent Incremental Contribution
CTL[b]	4.8	28
Oil Shale	3.0	17
EOR[c]	2.6	15
Biomass[d]	3.8	22
Transportation Energy Efficiency	3.0	17
TOTAL	17.2	100

[a]Incremental contribution, above the base case level, required.
[b]0.8 MM bpd of CTL is included in the base case; therefore, total CTL production in 2030 is 5.6 MM bpd.
[c]0.2 MM bpd of EOR is included in the base case; therefore, total EOR production in 2030 is 2.8 MM bpd.
[d]0.7 MM bpd of biomass (ethanol) is included in the base case; therefore, total biomass production in 2030 is 4.5 MM bpd.

[1]U.S. Energy Information Administration, *AEO 2006*, op. cit.

Table VI-2 shows the total contribution of each initiative (including the contributions in the base case) to U.S. liquid fuels requirements in the Energy Security and Independence case in 2030. In this case, the initiatives are supplying just over two-thirds of total U.S. liquid fuels requirements, with CTL supplying the greatest share (20 percent), followed by biomass (16 percent), oil shale (11 percent), transportation energy efficiency and conservation (11 percent), and EOR (10 percent).

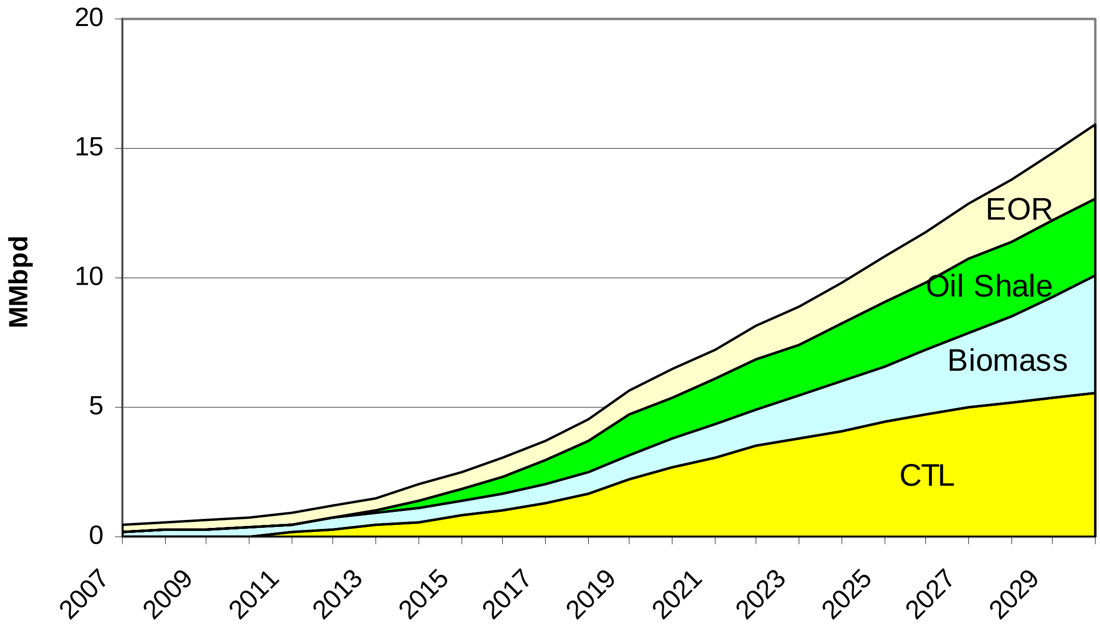
Thus, under the AES scenario, the substitute liquid fuels options will be providing nearly 60 percent of U.S. liquid fuels requirements, CTL will be providing about one-fifth of U.S. liquid fuels requirements, and biomass more than one-sixth. In essence, the structure of U.S. liquid fuels supply will be radically changed, with substitute fuels production from domestic sources replacing oil imports.

Table VI-2
Total Liquid Fuels Contributions From Each Initiative in 2030
Required to Achieve Energy Security and Independence

Initiative	MM Barrels/day Total Contribution Required in 2030	Percent Contribution to Total U.S. Liquid Fuels Requirements
CTL	5.6	20
Oil Shale	3.0	11
EOR	2.8	10
Biomass	4.5	16
Transportation Energy Efficiency	3.0	11
TOTAL	18.9	68

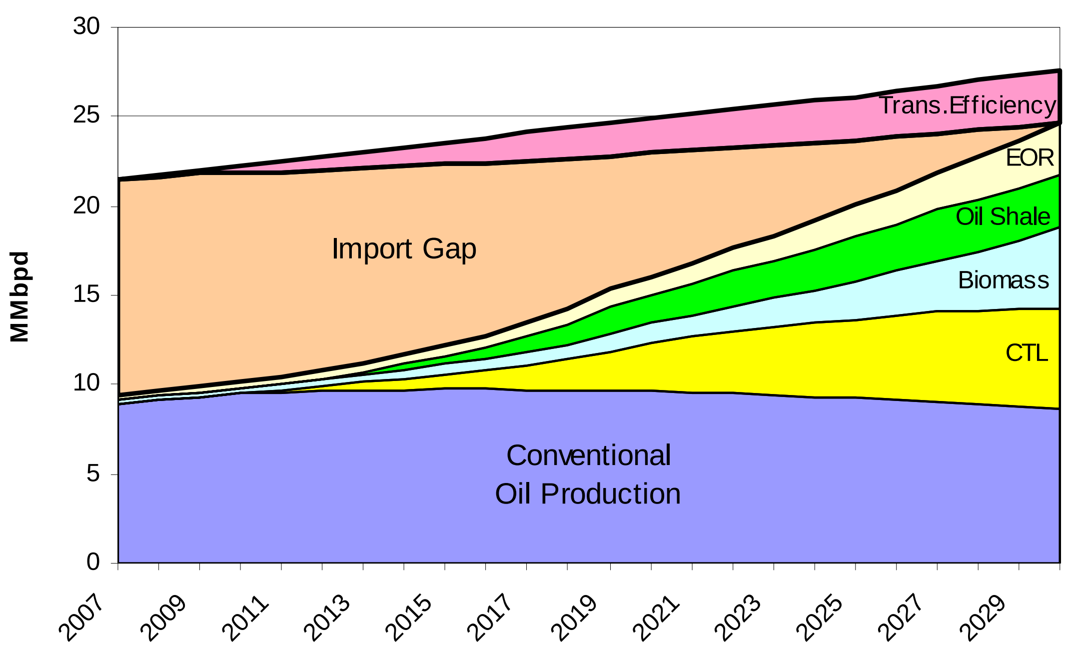
Our work demonstrates that the United States can become energy secure and independent by 2030, and a major goal of the analysis is to show how the U.S. can replace approximately five percent of U.S. imported oil each year for 20 years, beginning in 2010. A key to this plan will entail building multiple alternative liquid fuel plants each year, and this will require an enormous effort and commitments from industry, government, and the American people. Though a very ambitious goal, it can and must be achieved – as illustrated in Figures VI-1, VI-2, VI-3, and VI-4 and Table VI-2.

Figure VI-1
Ramp-up of the AES Liquid Fuel Supply Initiatives, 2007-2030



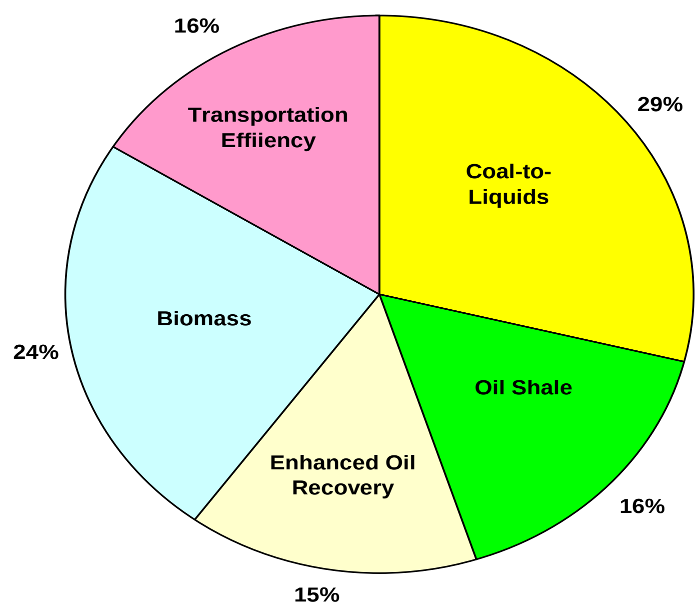
Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure VI-2
The Path to U.S. Energy Security and Independence



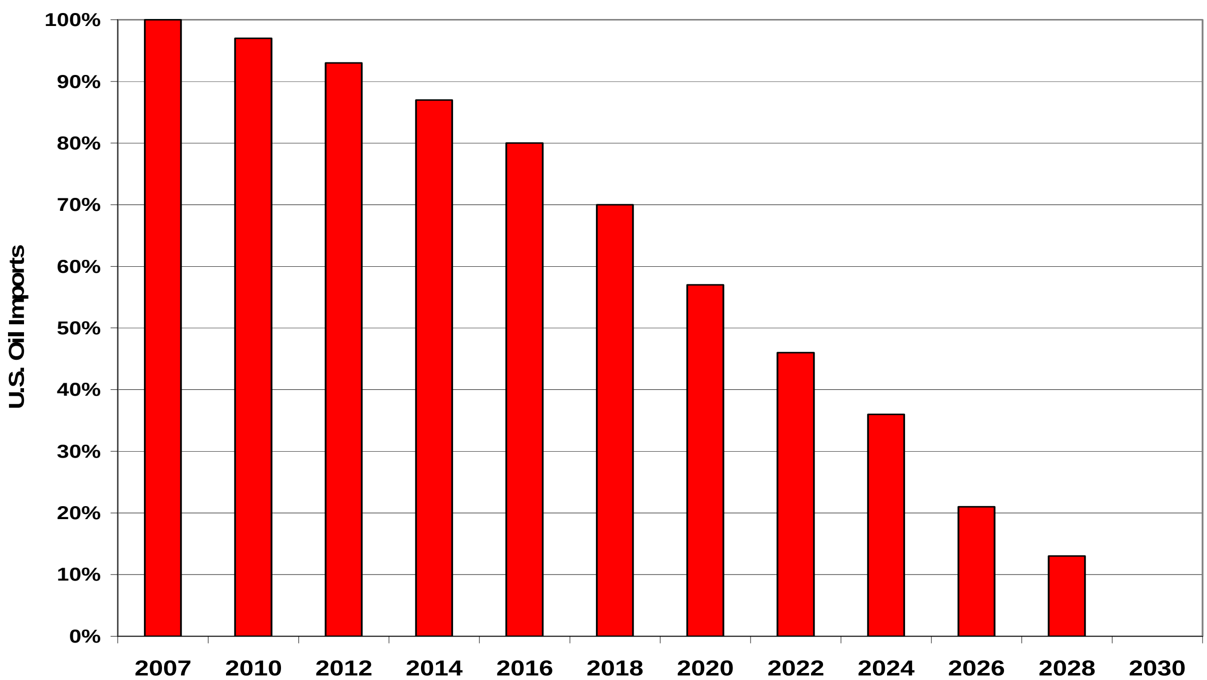
Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure VI-3: Contributions of the AES Initiatives in 2030 to Elimination of U.S. Oil Imports



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure VI-4: Reduction in U.S. Oil Imports Resulting From the AES Initiatives



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figure VI-1 and Table VI-3 show the ramp-up schedules of the four AES liquid fuel supply initiatives between 2007 and 2030. It illustrates that these supply options begin producing liquid fuels at different times and at different rates, and that their ultimate contributions to replacing U.S. oil imports differ considerably. For example:

- Biomass and EOR are already producing small amounts of liquid fuels in 2007, but the rate of growth of biomass fuels exceeds that of EOR – especially after 2020.
- CTL only begins to produce a small amount of liquid fuel in 2010, but it eventually grows to produce more liquid fuel than any of the other initiatives.
- Oil shale only begins to produce a small amount of liquid fuel in 2013, but grows rapidly after that.

Figure VI-2 illustrates how, by implementing the AES initiatives, the U.S. can eliminate oil imports by 2030. Even though U.S. conventional oil production continues to decline gradually over the next two decades, U.S. oil imports decline continuously. Overall liquid fuel requirements are reduced by transportation energy efficiency measures, and increasingly large amounts of new liquid fuels are produced from domestic U.S. resources: CTL, biomass, oil shale, and EOR. Assuming aggressive implementation beginning in 2007, under the SSEB AES initiatives liquid fuels production and savings begin gradually after 2010 and ramp up to produce most of the nation's liquid fuels requirements by 2030.

Figure VI-3 shows the contribution of each of the alternatives in 2030 to the elimination of U.S. oil imports:

- Coal-to-liquids replaces 29 percent of U.S. oil imports
- Biomass replaces 24 percent of U.S. oil imports
- Transportation energy efficiency reduces imports by 16 percent
- Oil shale replaces 16 percent of U.S. oil imports
- Enhanced oil recovery replaces 15 percent of U.S. oil imports

Table VI-2 shows that, under the SSEB AES program, by 2030 the initiatives are producing and saving liquid fuels equivalent to two-thirds of U.S. total requirements. Specifically:

- Coal-to-liquids is producing 5.6 million barrels per day (MM bpd) of liquid fuels – one fifth of U.S. liquid fuel requirements.
- Biomass is producing 4.5 MM bpd of liquid fuels – 16 percent of U.S. liquid fuel requirements.
- Transportation energy efficiency is saving the equivalent of 11 percent of U.S. fuel requirements.
- Oil shale is producing 3 MM bpd of liquid fuels – 11 percent of U.S. liquid fuel requirements.

- Enhanced oil recovery shale is producing 2.8 MM bpd of liquid fuels – one-tenth of U.S. liquid fuel requirements.

Table VI-3
Annual Liquid Fuel Contributions From Each of the AES Initiatives, 2007-2030

	CTL	Oil Shale	EOR	Biomass	TE&C	Total
	(MMbpd)					
2007	-	-	0.2	0.2	0.05	0.5
2008	-	-	0.3	0.2	0.10	0.6
2009	-	-	0.3	0.3	0.15	0.8
2010	0.03	-	0.4	0.3	0.4	1.1
2011	0.15	-	0.4	0.4	0.6	1.5
2012	0.3	-	0.5	0.4	0.8	1.9
2013	0.5	0.10	0.5	0.5	0.9	2.5
2014	0.6	0.3	0.6	0.5	1.1	3.1
2015	0.8	0.5	0.6	0.6	1.3	3.7
2016	1.0	0.7	0.7	0.7	1.4	4.4
2017	1.3	0.9	0.8	0.7	1.6	5.3
2018	1.7	1.2	0.9	0.8	1.7	6.2
2019	2.2	1.6	1.0	1.0	1.8	7.5
2020	2.7	1.6	1.1	1.1	1.9	8.4
2021	3.1	1.8	1.2	1.2	2.0	9.3
2022	3.5	2.0	1.3	1.4	2.1	10.3
2023	3.8	2.0	1.4	1.6	2.3	11.1
2024	4.1	2.3	1.6	1.9	2.4	12.2
2025	4.4	2.5	1.7	2.2	2.5	13.3
2026	4.7	2.7	1.9	2.5	2.6	14.3
2027	5.0	2.9	2.1	2.9	2.7	15.5
2028	5.2	2.9	2.3	3.3	2.8	16.6
2029	5.4	3.0	2.6	3.9	2.9	17.7
2030	5.6	3.0	2.8	4.5	3.0	18.9

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Figures VI-2 and VI-4 illustrate how the SSEB AES program will eliminate U.S. oil imports over the next two decades. Assuming initiation in 2007, the programs begin to displace a small portion of U.S. oil imports after 2010. As the programs ramp up over the decade, they being to replace a larger portion of U.S. oil imports every year:

- By 2015, the AES initiatives replace about 16 percent of U.S. oil imports.
- By 2020, the AES initiatives replace about 43 percent of U.S. oil imports.
- By 2025, they replace nearly three-quarters of U.S. oil imports.
- By 2030, the AES initiatives replace all of U.S. oil imports.

Tables VI-4, VI-5, VI-6, and VI-7 give the detailed ramp-up schedules through 2030 for each of the AES liquid fuel supply options.

Table VI-4
CTL Roll-out Through 2030 Under the AES Initiative

	Plants in Operation (number)	Liquid Fuel Output (MMbpd)		Plants in Operation (number)	Liquid Fuel Output (MMbpd)
2007	0	-	2019	91	2.2
2008	0	-	2020	108	2.7
2009	0	-	2021	122	3.1
2010	4	0.05	2022	134	3.5
2011	8	0.15	2023	145	3.8
2012	13	0.3	2024	155	4.1
2013	19	0.5	2025	165	4.4
2014	26	0.6	2026	175	4.7
2015	34	0.8	2027	184	5.0
2016	43	1.0	2028	192	5.2
2017	54	1.3	2029	199	5.4
2018	71	1.7	2030	206	5.6

Source: Southern States Energy Board, 2006.

This information has several crucial implications. First, to achieve U.S. energy security and independence by 2030 all feasible demand and supply options must be aggressively pursued. There is no single magic bullet:

- Transportation energy efficiency is important but, by itself, can contribute only a small portion of the required solution.
- Renewable biomass fuels are a critical part of the portfolio of required initiatives, but can produce less than one-fourth of the required liquid fuels.
- CTL, oil shale, and EOR will all contribute substantially, but all three technologies must be aggressively developed and expanded.

Second, all of the options presented here are technologically feasible, rely on domestic U.S. resources, and are capable of attaining the goals established over the next two decades. The resource assessments, technology assessments, costs, and forecasts were developed by experts in their respective fields.

Table VI-5
Biomass Roll-out Through 2030 Under the AES Initiative*

Year	Cellulosic Ethanol	Pyrolysis	Gasification & F-T	# Total Facilities	Production (annual basis, thousand of barrels/day)
2008	-	19	4	25	22
2009	-	36	8	39	44
2010	-	64	14	57	79
2011	15	75	18	72	107
2012	32	87	22	84	141
2013	51	101	28	100	179
2014	73	117	35	117	224
2015	98	135	43	139	277
2016	127	157	54	164	338
2017	159	182	68	195	409
2018	196	211	84	231	492
2019	239	245	106	274	589
2020	287	284	132	326	703
2021	342	330	165	388	836
2022	404	382	206	463	993
2023	476	443	258	552	1,177
2024	557	514	322	660	1,394
2025	650	597	403	791	1,650
2026	756	692	503	948	1,952
2027	877	803	629	1,138	2,309
2028	1,014	931	787	1,369	2,732
2029	1,171	1,080	983	1,649	3,235
2030	1,350	1,253	1,229	1,988	3,833

*Incremental AES contributions to the base case -- in which biomass production increases from 0.2 MM bpd in 2008 to 0.7 MM bpd in 2030.

Source: Southern States Energy Board, 2006.

Third, as the above figures illustrate, achieving U.S. energy security and independence involves an energy policy paradigm shift and will require a massive, continuing, decades-long effort by the private and public sectors. Thus, appropriate fiscal, regulatory, and institutional support mechanisms must be put in place and remain in effect for two decades.

Finally, and most important, time is of the essence: Implementation of the AES initiatives must begin no later than 2007 and delay is not an option. This study finds that, even with aggressive implementation of all of the initiatives starting next year, it will take at least a decade for them to begin to significantly reduce U.S. oil imports, and well over two decades to achieve national energy security and independence. Any delay will leave U.S. energy security at increasing risk.

Table VI-6
Oil Shale Roll-out Through 2030 Under the AES Initiative

Year	In-situ Facilities	Retort Surface Facilities[c]	Retort Underground Facilities[d]	Total Number of Facilities	Production (annual basis, thousand of barrels/day)
2013	1[a]			1	100
2014		1		1	300
2015			1	1	450
2016		1		1	650
2017	1[a]		1	2	900
2018	1[b]		1	2	1,150
2019			1	1	1,550
2020			1	1	1,600
2021	1[a]			1	1,750
2022			1	1	1,950
2023			1	1	2,000
2024			1	1	2,250
2025		1	1	2	2,500
2026	1[b]		1	2	2,650
2027			1	1	2,850
2028			1	1	2,900
2028			1	1	2,950
2030			1	1	3,000
Total	5	3	14	22	

[a]In-situ plants initially at 100,000 bpd, ramping up to 500,000 bpd in four years.
[b]In-situ plants initially at 100,000 bpd, ramping up to 250,000 bpd the next year.
[c]All retort surface facilities are 100,000 bpd.
[d]All retort underground facilities are 50,000 bpd.

Source: Southern States Energy Board, 2006.

Table VI-7
EOR Roll-out Through 2030 Under the AES Initiative

Year	Facilities Added this Year	Production Added this Year (thousand of barrels/day)	Facilities Total	Production Total (annual basis, thousand of barrels/day)
2010	12	37	130	390
2011	14	41	144	431
2012	15	45	159	476
2013	16	49	175	525
2014	18	55	193	580
2015	21	61	214	641
2016	22	67	236	708
2017	25	74	261	782
2018	27	82	288	864
2019	30	90	318	954
2020	33	100	351	1054
2021	37	110	388	1164
2022	40	121	428	1285
2023	45	135	473	1420
2024	50	148	523	1568
2025	54	164	577	1732
2026	61	181	638	1913
2027	66	200	704	2113
2028	74	221	778	2334
2029	81	244	859	2578
2030	90	269	949	2847

Source: Southern States Energy Board, 2006.

VI.B. The Economic Impacts of the AES Initiatives

The economic, national security, and environmental advantages of establishing a thriving domestic alternative liquid fuels industry vastly outweigh the development costs. In contrast, doing little or nothing subjects the U.S. to energy supply disruptions and to potentially severe economic consequences.

This study demonstrates that embarking on a national mission to achieve energy security and move toward liquid fuels independence will not only reduce risk and lower oil prices and oil price volatility, it will also facilitate an industrial boom, create millions of jobs, foster new technology, enhance economic growth, help to eliminate the trade and budget deficits, insure affordable energy for citizens and strategic fuels for the military, and establish a reliable domestic energy base upon which to rebuild U.S. industries to be globally competitive.

Table VI-8 summarizes the major economic benefits resulting from investments in the AES initiatives. It illustrates that by 2030, the AES initiatives generate *annually* (2005 dollars):

- New investments of nearly $200 billion
- One-third of a trillion dollars in increased industry sales
- More than 1.4 million new jobs
- $14 billion in profits
- Nearly $100 billion in increased federal, state, and local government tax revenues.
- A reduction of over $600 billion in the U.S. trade deficit

Table VI-8
Summary of the Economic Impacts of the AES Initiatives
(dollars in billions of 2005 dollars)

	2020	**2030**
AES Initiatives Capital Expenditures	$51	$53
AES Initiatives O&M Expenditures	$49	$132
Total Industry Sales Generated	$182	$332
Jobs Created	894,000	1,403,000
Industry Profits	$8	$14
Federal, State, and Local Government Tax Revenues Generated	$56	$94
Reduction in U.S. Trade Deficit	$250	$625

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Impact on Sales, Jobs, and Industries

We estimated the total (direct plus indirect) impacts of the AES initiatives and determined that it they will increase industry sales and employment substantially. As illustrated in Tables VI-9 through VI-12 and Figures VI-5 and VI-6, the AES initiatives:

- Generate $182 billion in total industry sales in 2020 and $332 billion in 2030.
- Generate nearly 900,000 new jobs in 2020 and more than 1.4 million new jobs in 2030.

While significant, the job estimates must be put into perspective: In 2010, U.S. employment is projected to total 142 million; in 2020 it is projected to total 156 million; in 2030 it is projected to total 174 million. Nevertheless, net job creation by the AES initiatives will be strongly positive.

Table VI-9
Industries With Largest Growth in Sales in 2020 Due to the AES Initiatives
(Billions of 2005 dollars)

Construction	$24.5
Motor vehicles, bodies and trailers, and parts	14.3
Petroleum and coal products	10.4
Miscellaneous professional, scientific and technical services	9.4
Wholesale trade	8.3
Fabricated metal products	7.5
Mining, except oil and gas	6.7
Oil and gas extraction	6.6
Primary metals	6.5
Farms	5.3
Chemical products	4.8
Truck transportation	3.9
Machinery	3.7
Management of companies and enterprises	3.7
Federal Reserve banks, credit intermediation, and related activities	3.3
Rental and leasing services and leasers of intangible assets	3.1
Broadcasting and telecommunications	3.0
Forestry, fishing, and related activities	2.7
Nonmetallic mineral products	2.3
Computer and electronic products	2.3
All other industries	50.0
Total, all industries	$182.2

Source: Management Information Services, Inc., 2006.

As discussed in Appendix E, we estimated the impacts of the AES initiatives on economic output and employment within the 70-order two- and three-digit NAICS code industries.[1] In general, in terms of industry sales and jobs we found that throughout the forecast period the construction, petroleum and coal products, mining, professional, scientific, and technical services, oil and gas, motor vehicles, forestry, farming, and related industries would be major beneficiaries. Except for a few industries such as trucking, larger sales are generated in each industry in 2030 than in 2020. For example, in terms of total industry sales, as shown in Tables VI-9 and VI-10 and in Figure VI-5:

- In 2020, sales in the construction industry increase by $25 billion and in 2030 sales increase by $30 billion.
- In year 2020, sales in the petroleum and coal products industry increase by $10 billion and in 2030 sales increase by $30 billion.
- In 2020, mining industry sales increase by $7 billion and in 2030 sales increase by $12 billion.

[1]NAICS: North American Industry Classification System.

- In 2020, sales in the professional, scientific, and technical services industry increase by $9 billion and in 2030 sales in this industry increase by $13 billion.
- In 2020, sales in the farming industry increase by $5 billion and in 2030 sales increase by $36 billion.
- In 2020, sales in the oil and gas industry increase by $7 billion and in 2030 sales increase by $30 billion.
- In 2020, sales in the motor vehicles industry increase by $14illion and in 2030 sales increase by $17 million.

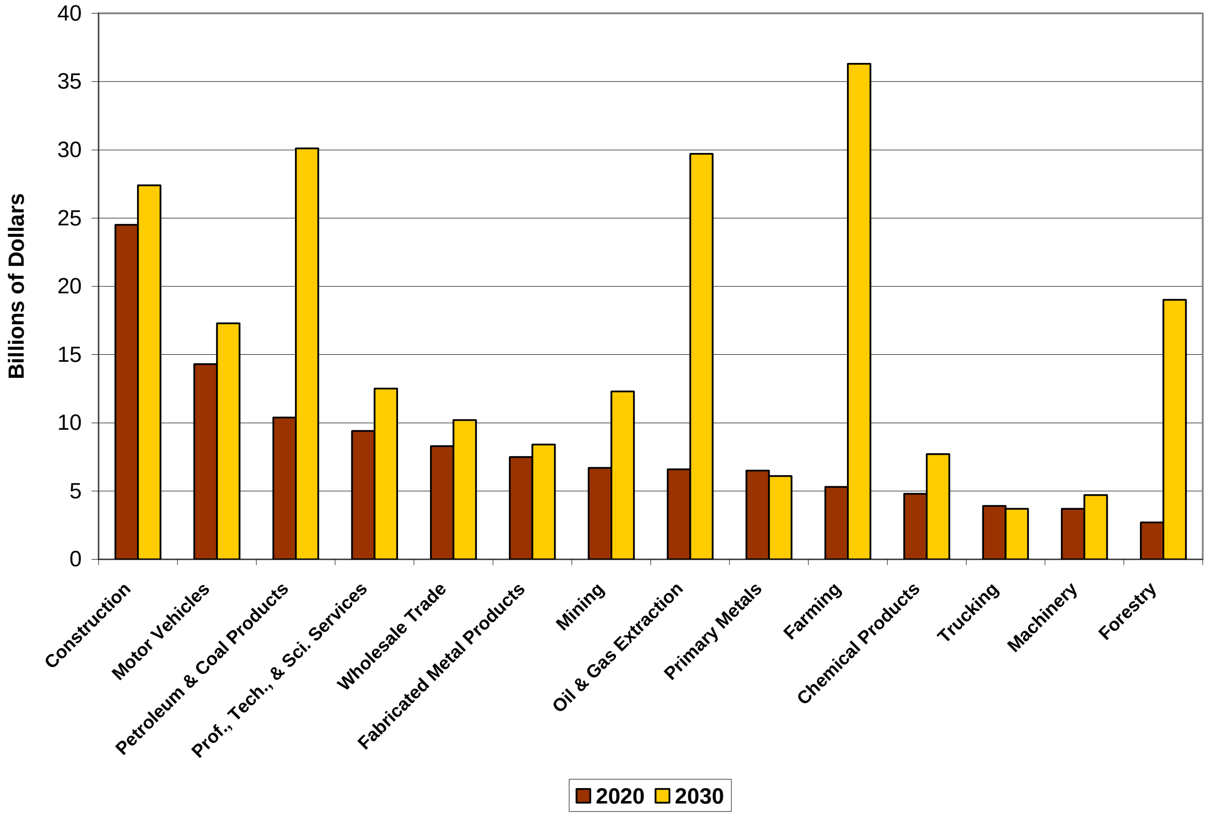
Table VI-10
Industries With Largest Growth in Sales in 2030 Due to the AES Initiatives
(Billions of 2005 dollars)

Farms	$36.3
Petroleum and coal products	30.1
Oil and gas extraction	29.7
Construction	27.4
Forestry, fishing, and related activities	19.0
Motor vehicles, bodies and trailers, and parts	17.3
Miscellaneous professional, scientific and technical services	12.5
Mining, except oil and gas	12.3
Wholesale trade	10.2
Fabricated metal products	8.4
Chemical products	7.7
Pipeline transportation	6.8
Rental and leasing services and leasers of intangible assets	6.4
Primary metals	6.1
Management of companies and enterprises	5.6
Utilities	5.6
Federal Reserve banks, credit intermediation, and related activities	5.3
Machinery	4.7
Real estate	4.0
Truck transportation	3.7
All other industries	73.3
Total, all industries	$332.2

Source: Management Information Services, Inc., 2006.

As shown in Tables VI-11 and VI-12, the increases in industry employment in each year are analogous to the increases in industry sales, although there are some differences due to the different productivity and labor intensity structures among industries. Except for a few industries such as nonmetallic mineral products, more jobs are generated in each industry in 2030 than in 2020. For example, in terms of jobs, as shown in Tables VI-11 and VI-12 and in Figure VI-6:

Figure VI-5
Sales Created in Select Industries by the AES Initiatives in 2020 and 2030



Source: Management Information Services, Inc., 2006.

With respect to the job increases in different industries:

- In 2020, 190,000 jobs are created in the construction industry and in 2030 207,000 jobs are created in this industry.
- In 2020, 48,000 jobs are created in the professional, scientific and technical services industry and in 2030 63,000 jobs are created in this industry.
- In 2020, 41,000 jobs are created in the fabricated metal products industry and in 2030 44,000 jobs are created in this industry.
- In 2020, 47,000 jobs are created in the wholesale trade industry and in 2030 56,000 jobs are created in this industry.
- In 2020, 27,000 jobs are created in the mining industry and in 2030 48,000 jobs are created in this industry.
- In 2020, 24,000 jobs are created in the farming industry and in 2030 158,000 jobs are created in this industry.
- In 2020, 15,000 jobs are created in the forestry industry and in 2030 75,000 jobs are created in this industry.

- In 2020, 12,000 jobs are created in the oil and gas industry and in 2030 65,000 jobs are created in this industry.

Table VI-11
Industries With Largest Growth in Jobs in 2020 Due to the AES Initiatives
(number of jobs in thousands)

Construction	190
Administrative and support services	49
Miscellaneous professional, scientific and technical services	48
Wholesale trade	47
Other services, except government	45
Fabricated metal products	41
Retail trade	35
Motor vehicles, bodies and trailers, and parts	31
Truck transportation	30
Mining, except oil and gas	27
Farms	24
Management of companies and enterprises	18
Machinery	17
Federal Reserve banks, credit intermediation, and related activities	16
Forestry, fishing, and related activities	15
Plastics and rubber products	14
Primary metals	13
State and local government enterprises	13
Other transportation and support activities	12
Nonmetallic mineral products	12
All other industries	197
Total, all industries	894

Source: Management Information Services, Inc., 2006.

Construction is the industry in which sales and employment increase the most, although in 2030 this industry accounts for a smaller portion of the increase in sales and jobs than in 2020. Specifically, in this industry:

- In 2020, sales of $25 billion represent 13 percent of total sales of $182 billion.
- In 2030, sales of $27 billion represent 8 percent of total sales of $332 billion.
- In 2020, employment of 190,000 represents 21 percent of the total 894,000 jobs created.
- In 2030, employment of 207,000 represents 15 percent of the total 1.4 million jobs created.

Table VI-12
Industries With Largest Growth in Jobs in 2030 Due to the AES Initiatives
(number of jobs in thousands)

Construction	207
Farms	158
Forestry, fishing, and related activities	75
Administrative and support services	70
Oil and gas extraction	65
Miscellaneous professional, scientific and technical services	63
Wholesale trade	56
Mining, except oil and gas	48
Other services, except government	46
Fabricated metal products	44
Retail trade	41
Motor vehicles, bodies and trailers, and parts	36
Truck transportation	32
State and local government enterprises	29
Management of companies and enterprises	26
Federal Reserve banks, credit intermediation, and related activities	23
Machinery	17
Other transportation and support activities	13
Nonmetallic mineral products	12
Support activities for mining	10
All other industries	331
Total, all industries	1,403

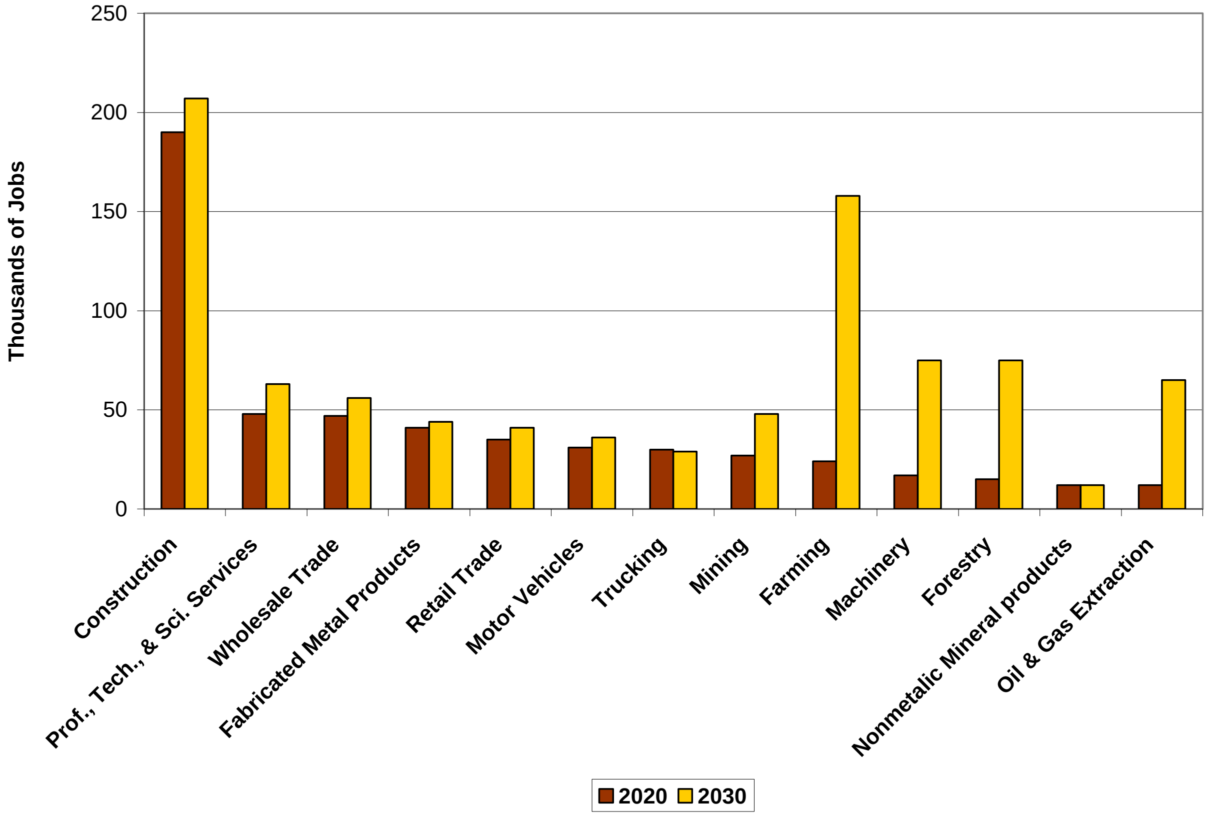
Source: Management Information Services, Inc., 2006.

Industry Profits

The increase in industry sales generated by the CTL mitigation initiative will create substantial profits for the industries. Applying the estimates of profit margins by detailed industry to the increased sales in each industry indicates that:

- In 2020, the AES initiatives result in industry profits of approximately $8.2 billion.
- In 2030, the AES initiatives result in industry profits of approximately $14.4 billion

Figure VI-6
Jobs Created in Select Industries by the AES Initiatives in 2020 and 2030



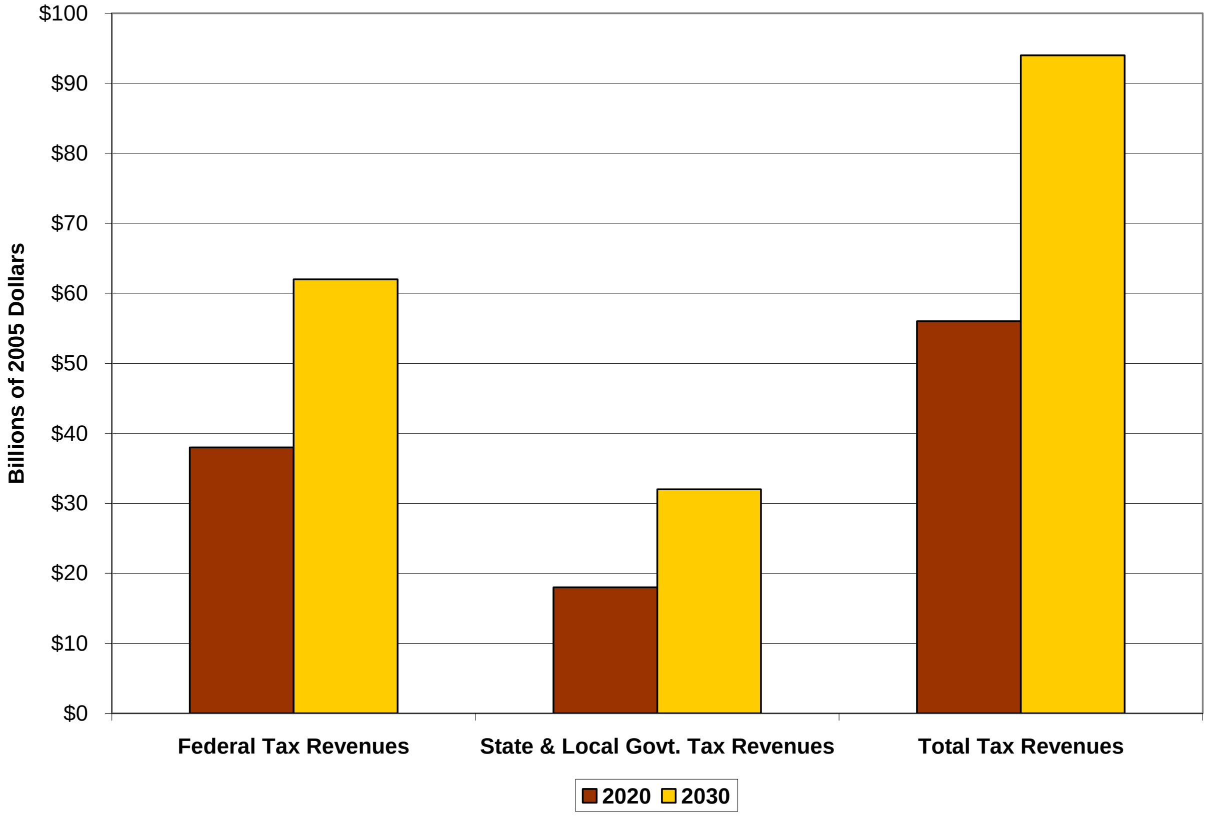
Source: Management Information Services, Inc., 2006.

Federal, State, and Local Government Tax Revenues

The increased sales and incomes created by the CTL mitigation option will generate substantial federal, state, and local government tax revenues; specifically, as shown in Figure VI-7:

- In 2020, the AES initiatives generate approximately $56 billion in tax revenues: $38 billion in federal tax revenues and $18 billion in state and local tax revenues.
- In 2030, the AES initiatives generate approximately $94 billion in tax revenues: $62 billion in federal tax revenues and $32 billion in state and local tax revenues.

Figure VI-7
Increased Tax Revenues Generated by the AES Initiatives



Source: Management Information Services, Inc., 2006.

Summary of Major AES Initiative Impacts

The AES initiatives modeled here will provide substantial quantities of liquid fuels, will generate large requirements for the products and services of many industries, will generate substantial industry profits, will create large numbers of jobs, will reduce the U.S. trade deficit, and will generate significant federal, state, and local government tax revenues. The major impacts of the AES initiatives can be summarized as follows:

In 2020, the AES initiatives generate *annually* (2005 dollars):

- Production/saving of 8.4 MM bpd of liquid fuels
- New investments of $100 billion
- Nearly 200 billion dollars in increased industry sales
- Nearly 900,000 new jobs
- $8 billion in profits
- $56 billion in increased federal, state, and local government tax revenues.
- A reduction of $250 billion in the U.S. trade deficit

In 2030, the AES initiatives generate *annually* (2005 dollars):

- Production/saving of nearly 19 MM bpd of liquid fuels
- New investments of nearly $200 billion
- One-third of a trillion dollars in increased industry sales
- More than 1.4 million new jobs
- $14 billion in profits
- Nearly $100 billion in increased federal, state, and local government tax revenues.
- A reduction of over $600 billion in the U.S. trade deficit

VI.C. Impact on Jobs by Occupations and Skills

We disaggregated the employment generated by the AES initiatives into occupations and skills, as illustrated in Tables VI-13, VI-14, and VI-15, and Figures VI-7 and VI-8, for selected occupations in 2020 and 2030. Specifically:

- Table VI-13 illustrates the new jobs created in different occupations by the AES Initiatives in 2020 and 2030
- Table VI-14 shows the occupations in which the largest numbers of jobs are created by the AES initiatives in 2020
- Table VI-15 shows the occupations in which the largest numbers of jobs are created by the AES initiatives in 2030
- Figure VI-8 illustrates the jobs created for select occupations by the AES initiatives in 2020 and 2030
- Figure VI-9 illustrates the relative impacts of the AES jobs created in 2030 on selected occupations -- new jobs as a percent of total employment in the occupation

The jobs generated are disproportionately concentrated in fields related to the construction, energy, and industrial sectors, reflecting the requirements of the AES initiatives and their supporting industries. The AES initiatives will revitalize large sections of U.S. industry and will create an especially robust labor market and greatly enhanced employment opportunities in many industries and in professional and skilled occupations such as chemical, mechanical, electronics, petroleum, and industrial engineers; electricians; sheet metal workers; geoscientists; computer software engineers; skilled refinery personnel; tool and die makers; computer controlled machine tool operators; industrial machinery mechanics, electricians; oil and gas field technicians, machinists, engineering managers, electronics technicians, carpenters; welders; and others. However, it is also important to note that millions of jobs will be created at all skill levels for occupations such as laborers, farm workers, truck drivers, security guards, managers and administrators, secretaries, clerks, service workers, and so forth.

Table VI-13
Occupational Job Impacts of the AES Initiatives, 2020 and 2030
(Number of new jobs created in select occupations)

Occupation	2020	2030
Accountants and auditors	10,400	16,700
Agricultural equipment operators	400	5,000
Automotive mechanics and technicians	2,300	1,500
Bookkeeping, accounting, and auditing clerks	16,700	22,000
Brickmasons and blockmasons	2,500	2,000
Carpenters	11,500	12,600
Cashiers	10,100	9,800
Cement masons and concrete finishers	4,300	3,000
Civil engineers	1,500	2,000
Computer-controlled machine tool operators	1,100	1,200
Computer programmers	3,600	4,800
Computer support specialists	2,000	1,800
Computer systems analysts	2,200	3,800
Construction laborers	22,300	26,400
Construction managers	900	1,600
Cost estimators	3,900	4,600
Crushing and grinding machine operators and tenders	300	1,100
Customer service representatives	2,500	10,100
Cutting and press machine operators	2,000	1,600
Drywall and ceiling tile installers	2,700	2,200
Electrical and electronics engineers	900	1,000
Electrical power-line installers and repairers	400	1,100
Electricians	14,400	17,900
Electronic equipment assemblers	1,700	1,500
Excavating and loading machine operators	2,100	2,400
Executive secretaries and administrative assistants	7,500	12,200
Engineering managers	300	1,100
Extraction workers' assistants	400	1,800
Farmworkers and laborers, crop	2,500	51,700
Financial managers	2,000	2,400
First-line construction and extraction supervisors/managers	12,800	11,100
First-line farming and forestry supervisors/managers	400	3,000
First-line office and administrative supervisors/managers	1,200	2,600
First line production supervisors	5,100	3,600
Geoscientists	300	1,100
Glaziers	400	900
Graders and sorters, agricultural products	500	5,600
Heating, air conditioning, and refrigeration mechanics	3,600	2,600
Industrial engineers	2,200	2,100
Industrial machinery mechanics	3,700	5,300
Industrial production managers	1,200	1,200
Inspectors and testers	3,900	4,200
Janitors and cleaners	11,800	17,600
Laborers and stock movers	1,200	7,900
Landscaping and groundskeeping workers	500	2,200
Logging equipment operators	500	6,900
Machinists	4,800	5,000

Maintenance and repair workers	2,000	8,600
Management analysts	2,500	2,300
Mechanical engineers	2,500	2,200
Mobile heavy equipment mechanics	1,800	2,600
Oil and gas derrick operators,	500	1,800
Oil and gas rotary drill operators,	500	1,800
Oil and gas roustabouts	800	3,200
Oil, gas, and mining service unit operators	400	1,600
Office clerks, general	2,200	7,800
Operating engineers	9,600	14,700
Packaging and filling machine operators and tenders	600	1,300
Painters, construction and maintenance	5,800	5,600
Paving, surfacing, and tamping equipment operators	400	1,000
Petroleum engineers	300	1,300
Petroleum pump system and refinery operators	400	1,600
Pipelayers	400	1,000
Plasterers and stucco masons	500	1,000
Plumbers	10,900	13,000
Production, planning, and expediting clerks	3,500	3,700
Purchasing agents	1,300	1,400
Receptionists and information clerks	700	1,600
Reinforcing iron and rebar workers	400	900
Sales representatives, wholesale and manufacturing	1,800	5,600
Secretaries	2,300	9,000
Security guards	5,400	8,600
Shipping and receiving clerks	6,000	5,600
Sheet metal workers	3,400	2,600
Software engineers	4,000	4,200
Structural iron and steel workers	1,700	1,500
Team assemblers	8,800	7,600
Telecommunications equipment installers and repairers	500	1,100
Tile and marble setters	400	900
Tool and die makers	1,000	1,100
Truck drivers	21,100	27,600
Welders	5,400	5,900
Wellhead pumpers	300	1,300
Total, all occupations	894,000	1,403,000

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Table VI-14
Occupations in Which the Largest Numbers of Jobs are Created by the AES Initiatives in 2020
(Number of new jobs created)

Occupation	2020
Construction laborers	22,300
Truck drivers	21,100
Bookkeeping, accounting, and auditing clerks	16,700
Electricians	14,400
First-line construction and extraction supervisors/managers	12,800
Janitors and cleaners	11,800
Carpenters	11,500
Plumbers	10,900
Accountants and auditors	10,400
Cashiers	10,100
Operating engineers	9,600
Team assemblers	8,800
Executive secretaries and administrative assistants	7,500
Shipping and receiving clerks	6,000
Painters, construction and maintenance	5,800
Security guards	5,400
Welders	5,400
First line production supervisors	5,100
Machinists	4,800
Cement masons and concrete finishers	4,300

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

While workers at all levels in all sectors will greatly benefit from the AES initiatives, as noted, disproportionately large numbers of jobs will be generated for various professional, technical, and skilled occupations such as:

- Brickmasons
- Carpenters
- Civil engineers
- Computer analysts and specialists
- Computer-controlled machine tool operators
- Construction managers
- Cement masons
- Electricians
- Electrical and electronics engineers
- Engineering managers
- Geoscientists
- Industrial engineers
- Industrial machinery mechanics
- Logging equipment operators
- Machinists

- Mechanical engineers
- Oil and gas workers
- Operating engineers
- Petroleum engineers
- Petroleum system and refinery operators
- Pipelayers
- Plumbers
- Oil and gas drill operators
- Sheet metal workers
- Software engineers
- Structural iron and steel workers
- Tool and die makers
- Welders

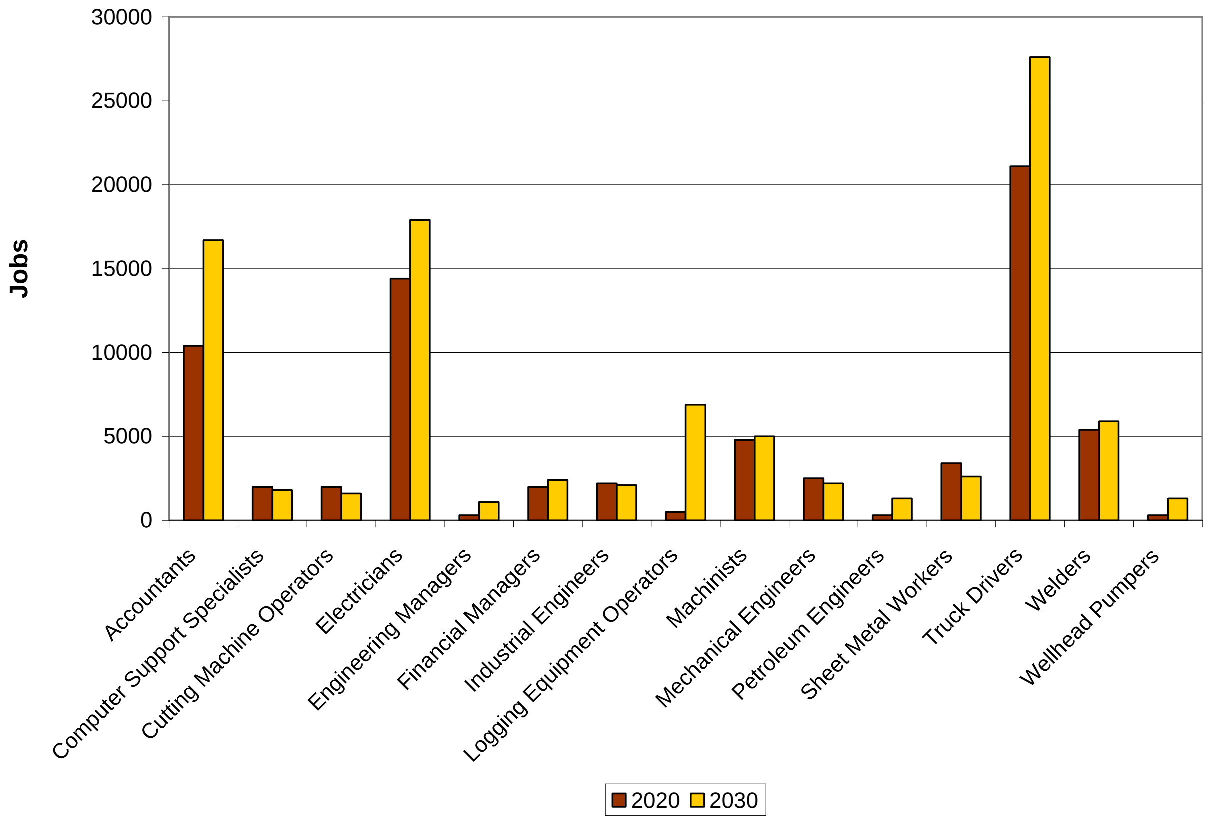
Table VI-15
Occupations in Which the Largest Numbers of Jobs are Created by the AES Initiatives in 2030
(Number of new jobs created)

Occupation	2030
Farmworkers and laborers, crop	51,700
Truck drivers	27,600
Construction laborers	26,400
Bookkeeping, accounting, and auditing clerks	22,000
Electricians	17,900
Janitors and cleaners	17,600
Accountants and auditors	16,700
Operating engineers	14,700
Plumbers	13,000
Carpenters	12,600
Executive secretaries and administrative assistants	12,200
First-line construction and extraction supervisors/managers	11,100
Customer service representatives	10,100
Cashiers	9,800
Secretaries	9,000
Maintenance and repair workers	8,600
Security guards	8,600
Laborers and stock movers	7,900
Office clerks, general	7,800
Team assemblers	7,600

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Accordingly, the importance of the AES initiatives for jobs in some occupations is much greater than in others. Some occupations, such as those listed above, will benefit greatly from the employment requirements generated by the initiatives. This is hardly surprising, for most of these jobs are clearly related to the construction, energy, scientific, and industrial sectors.

Figure VI-8
Jobs Created for Select Occupations
by the AES Initiatives in 2020 and 2030



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

However, it is also important to note that the jobs generated by the AES initiatives will be widely distributed among virtually all occupations and skill levels and, while the numbers of jobs created in different occupations vary substantially, employment in virtually all occupations will be generated. The vast majority of the jobs created by the AES initiatives will be standard jobs created, directly and indirectly, for accountants, engineers, bookkeepers, computer analysts, clerks, factory workers, security guards, truck drivers, technicians, sales representatives, analysts, mechanics, etc. For example, Table VI-13 shows that the AES initiatives will generate in 2030:

- More jobs for cashiers (9,800) than for geoscientists (1,100)
- More jobs for office clerks (7,800) than for software engineers (4,200)
- More jobs for construction laborers (26,400) than for operating engineers (14,700)
- More jobs for janitors (17,600) than for industrial production managers (1,200)

- More jobs for security guards (8,600) than for computer system analysts (3,800)
- More jobs for accountants and auditors (16,700) than for machinists (7,000)
- More jobs for truck drivers (27,600) than for oil and gas rotary drill operators (1,800)
- More jobs for secretaries (9,000) than for industrial engineers (2,100)
- More jobs for office clerks (7,800) than for petroleum engineers (1,300)
- More jobs for farm workers and laborers (51,700) than for sheet metal workers (2,600)

Thus, many workers will be dependent on the AES initiatives for their employment, even though they may not be aware of it.

As noted, disproportionately large numbers of jobs will be generated for various professional, technical, and skilled occupations concentrated in fields related to the construction, energy, and industrial sectors, reflecting the requirements of the AES initiatives and their supporting technologies and industries. Nevertheless, the largest number of jobs will be generated in occupations such as secretaries, security guards, laborers, truck drivers, etc. This is illustrated by examining the relative impact of jobs in different occupations – the jobs created relative to the total number of jobs in that occupation. This is necessary because the number of persons employed in different occupations differs greatly. For example, in 2004, there were employed in the U.S.:

- Over two million secretaries
- Nearly three million truck drivers
- Over one million accountants
- Nearly 700,000 electricians
- Nearly 500,000 financial mangers
- Over one million carpenters

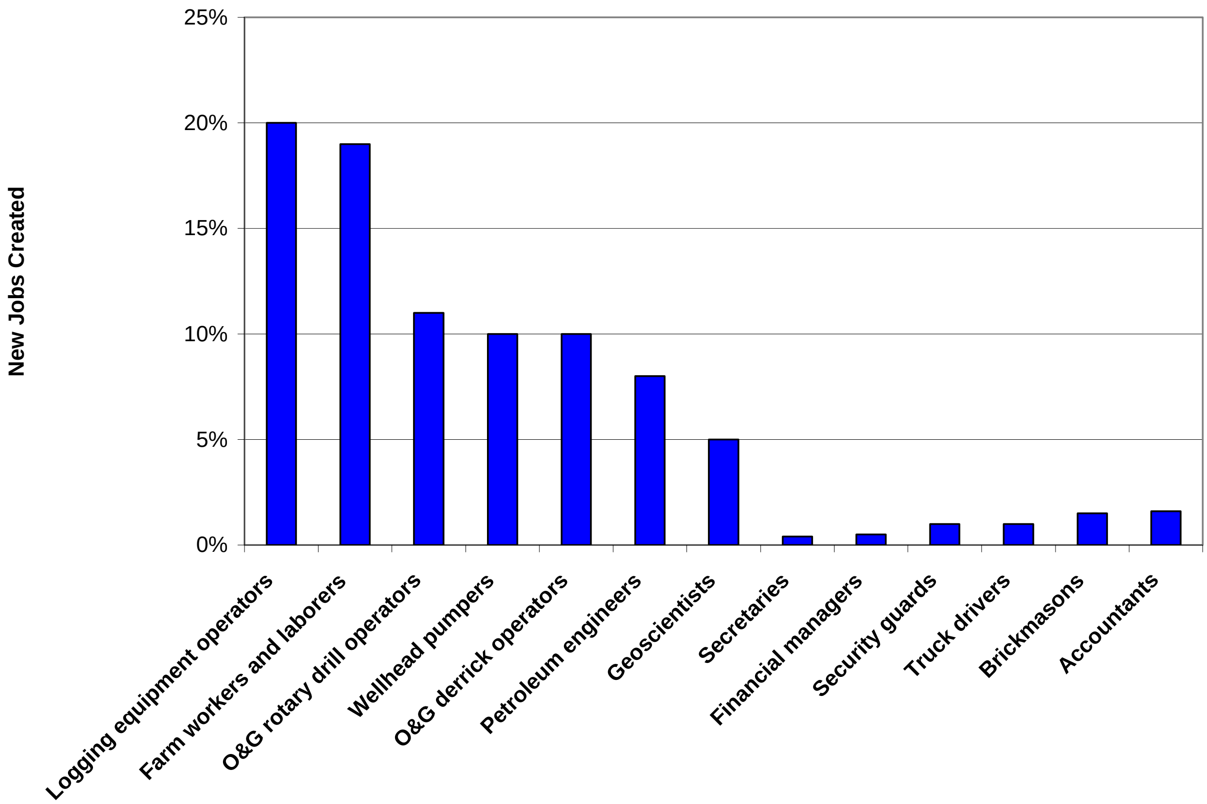
But there were only:

- 16,000 petroleum engineers
- 23,000 geoscientists
- 17,000 oil and gas rotary drill operators
- 12,000 wellhead pumpers
- 34,000 logging equipment operators

Thus, in 2030, for example, the AES initiatives have a widely differing impact on the relative employment requirements for different occupations – see Figure VI-8. On the one hand, some occupations are impacted very significantly, and in this year the AES initiatives increase the number of jobs for:

- Logging equipment operators by 20 percent
- Farm workers and laborers by 19 percent
- Oil and gas rotary drill operators by 11 percent
- Oil and gas derrick operators by 10 percent
- Wellhead pumpers by 10 percent
- Petroleum engineers by eight percent
- Geoscientists by five percent

Figure VI-9
Relative Impacts of the AES Jobs Created in 2030 on Selected Occupations
(New jobs as a percent of total employment in the occupation)



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

On the other hand, some occupations are impacted relatively little, even though large numbers of jobs are created. In 2030 the AES initiatives increase the number of jobs for:

- Secretaries by 0.4 percent
- Financial managers by 0.5 percent
- Security guards by one percent
- Truck drivers by one percent
- Brickmasons by 1.5 percent

- Accountants by 1.6 percent

VI.D. Scenario Analyses

The study included a base case, or Baseline Scenario, and four alternate scenarios. These are summarized below.

The Baseline Scenario assumes that world oil peaking will not occur within the next 25 years and that no major liquid fuel mitigation initiatives will be implemented. This represents a "business as usual" case and identifies the basic economic, demographic, technical, and institutional parameters that will be used in assessing the alternate scenarios. We then developed four alternate scenarios:

- Scenario 1: Accelerated Mitigation Technology Initiatives With no Oil Peaking. This scenario assumes that, even though oil peaking and supply shortfalls do not occur in the near future, the AES initiatives are implemented, beginning in 2007, in conjunction with an ambitious transportation fuel efficiency program.
- Scenario 2: Oil peaking in 2010, But no AES Initiatives. This scenario assumes that, even though world oil peaking occurs within four years, no aggressive mitigation programs are initiated.
- Scenario 3: The AES Initiatives With Oil Peaking in 2010. Scenario 3 assumes that oil peaking and supply shortfalls occur in 2010 and that the AES initiatives are implemented, beginning in 2007, in conjunction with an ambitious transportation fuel efficiency program.
- Scenario 4: Accelerated Mitigation Technology Initiatives With Oil Peaking in 2020. This scenario assumes that oil peaking and supply shortfalls occur in 2020 and that the AES initiatives are implemented, beginning in 2007, in conjunction with an ambitious transportation fuel efficiency program.

In his 2006 State of the Union Address, President Bush stated that the nation was "addicted to oil" and he articulated a goal of "reducing U.S. imports of Middle Eastern oil by 75 percent by 2025." We did not model this as a separate scenario. Rather, we assessed the potential of the AES initiatives with respect to their potential impact on reducing U.S. oil imports from the Middle East.

Baseline Scenario

The Baseline Scenario assumes that world oil peaking will not occur within the next 25 years. This represents a "business as usual" case and establishes the basic economic, demographic, technical, and institutional parameters that were used in the analysis. We used the latest U.S Energy Information Administration (EIA) long-range forecasts through 2030 to develop the baseline scenario.[1] The EIA forecasts are in widespread use and are relied upon by government and industry decision-makers.

Use of the EIA forecasts to develop the baseline scenario made it possible to estimate the impacts and benefits of the AES initiatives. For example:

- In 2030, EIA projects that under the reference case, oil will be $57/bbl. (2004 dollars), and that under the high oil price case oil will be $96/bbl. (2004 dollars)
- EIA projects that, by 2030, U.S. petroleum imports will total 62 percent of domestic consumption under the reference case, and 52 percent of domestic consumption under the high oil price case. As noted, the current study shows how aggressive implementation of the AES initiatives could eliminate U.S. oil imports by 2030.
- EIA projects that by 2025 under the reference case, U.S. production of substitute liquid fuels will total 580,000 bpd of CTL and 650,000 bpd of ethanol. By 2030 EIA projects, that, under the reference case, CTL production will total 760,000 bpd and ethanol production will total 700,000.[2] The current study shows that the AES initiatives will result in the production of many millions of barrels of substitute liquid fuels per day well before 2030.

The EIA reference case does not formally factor in oil peaking into its projections.[3] In developing the baseline scenario we retained most of the parameters and assumptions of the latest EIA reference case forecasts, and made limited use of the forecasts in the EIA high oil price case.

Development of the baseline data is necessary for at least two reasons. First, this is essentially current U.S. policy and includes the recently signed EPAct 2005, and

---

[1] U.S. Energy Information Administration, *Annual Energy Outlook 2006 With Projections to 2030*, February 2006.

[2] Under the high oil price case, EIA projects that in 2030 U.S. CTL production will total 1.7 MM bpd and ethanol production will total 900,000 bpd.

[3] In 2000, EIA developed 12 scenarios for world oil production peaking using three USGS estimates of the world conventional oil resource base (Low, Expected, and High) and four annual world oil demand growth rates (0, 1, 2, and 3 percent per year) – see EIA, "Long Term World Oil Supply," April 18, 2000. These scenarios can be interpreted as projecting oil peaking between 2016 and 2037. The EIA scenario that peaks in 2016 resembles the relatively symmetric U.S. Lower 48 production profile. The EIA scenario that peaks in 2037 not only differs dramatically from the U.S. experience, it differs from typical individual oil reservoir experience, which often displays a relatively symmetric production profile. On this basis, in the 2005 MISI/SAIC study for DOE (*Peaking Of World Oil Production: Impacts, Mitigation, & Risk Management*, February 2005) concluded that assuming peaking in 2016 was more credible than assuming peaking in 2037 and that the associated 21-year difference between the two production peaks would have profound implications for the time available for mitigation. The study labeled this case the EIA "nominal" case: It is inferred from EIA and USGS data and forecasts. This is discussed in more detail in Appendix 1, pp. 69-70, of the MISI/SAIC study. EIA has never issued an official estimate of the date of peaking. However, AEO 2006, if read carefully, indicates that EIA is concerned about the issue and acknowledges "the eventual peaking of world oil production." See EIA, *Annual Energy Outlook 2006 With Projections to 2030*, February 2006, p. 47.

may continue for the foreseeable future until a major liquid fuels crisis occurs. Second, the implications of this scenario can usefully be compared and contrasted with the benefits of beginning the AES initiatives in 2007. After the baseline data were developed – See Tables VI-16 and VI-17, four scenarios were constructed to identify the alternative options that were considered and to compare the impacts of these options against the baseline scenario.

Scenario 1: Accelerated Mitigation Technology Initiatives With no Oil Peaking

Scenario 1 assumes that, even though oil peaking and supply shortfalls do not occur in the near future, the AES initiatives are implemented, beginning in 2007, in conjunction with an ambitious transportation fuel efficiency program. This scenario considers the case where world oil peaking does not occur prior to 2030 and ambitious substitute fuels initiatives are initiated in 2007. Analysis of this scenario illustrates the national security, economic, employment, and related benefits of initiating the AES program even in the absence of near-term world oil peaking.

Scenario 1 assumed implementation beginning in 2007 of the AES initiatives. On the supply side, the following technical options feasible for the U.S. were included:

- Coal-to-liquids
- Oil shale
- Biomass
- Polygeneration[1]
- Improved oil recovery, especially CO_2 enhanced oil recovery (EOR)

Other technically feasible options, such as oil sands and gas-to-liquids, are not supported by the U.S. resource base.

[1]The term polygeneration refers to the simultaneous production of several energy-related products, and polygeneration plants will be able to produce a broad variety of needed products, including liquid fuels for transportation, steam, methane (natural gas), electricity, hydrogen, and other chemical and construction aggregate products. See Southern States Energy Board, *American Energy Security: Building a Bridge to Energy Independence and a Sustainable Energy Future*, July 2005.

Table VI-16
Economic Indicators Based on EIA Reference Case

	2005	2010	2015	2020	2025	2030	Annual Change 2005-2030
Gross Domestic Product (billion '05$)	12,503	14,630	16,917	19,675	22,572	25,925	3.0%
Consumption	8,814	10,238	11,636	13,366	15,204	17,221	2.7%
Investment	2,159	2,534	3,043	3,694	4,515	5,592	3.9%
Government Spending	2,229	2,412	2,575	2,764	2,951	3,183	1.4%
Exports	1,351	2,054	2,996	4,236	5,702	7,664	7.2%
Imports	2,054	2,575	3,205	4,104	5,310	6,905	5.0%
Energy Intensity (tbtu/'05$GDP)	8.04	7.38	6.75	6.14	5.63	5.17	-1.8%
GDP Price Index ('05=100)	100	110	125	143	162	183	2.4%
CPI - All-Urban ('05=100)	100	110	126	147	170	194	2.7%
Energy Commodities and Services	100	96	107	126	148	171	2.2%
WPI ('05=100)	100	100	107	117	128	137	1.3%
Fuel and Power	100	91	100	118	142	166	2.1%
Federal Funds Rate (%)	3.24	5.30	5.46	5.24	5.01	5.04	-
10-Year Treasury Note Rate (%)	4.43	5.92	6.11	6.21	6.14	6.13	-
AA Utility Bond Rate (%)	5.64	7.55	7.69	8.15	8.35	8.52	-
Value of Shipments (billion '05$)	6,466	7,129	7,892	8,724	9,634	10,743	2.1%
Non-Manufacturing	1,667	1,764	1,895	2,029	2,160	2,321	1.3%
Manufacturing	4,800	5,365	5,998	6,696	7,474	8,423	2.3%
Population (millions)	297	310	324	337	351	365	0.8%
Labor Force (millions)	149	159	163	168	173	181	0.8%
Total Nonfarm Employment (millions)	134	142	148	156	164	174	1.1%
Employment, Manufacturing	14	14	14	13	13	13	-0.5%
Nonfarm Labor Productivity ('05=100)	100	111	126	141	157	176	2.3%
Unemployment Rate (percent)	5.1	4.7	4.6	4.4	4.8	4.9	-
Disposable Personal Income (billion'05$)	9,235	10,873	12,495	14,755	17,156	19,845	3.1%
Housing Starts (millions)	2.16	1.97	1.95	1.89	1.83	1.82	-0.7%
Commercial Floorspace (billion sq. ft.)	76.2	82.3	88.9	96.0	103.7	112.0	1.6%
Unit Sales of Light-Duty Vehicles (millions)	16.9	17.6	18.0	18.9	20.3	21.8	1.0%
Imported Crude Oil Price ('04$)	49.70	43.99	43.00	44.99	47.99	49.99	0.0%
Low Sulfur Light	55.93	47.29	47.79	50.70	54.08	56.97	0.1%

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, and Management Information Services, Inc., 2006.

Table VI-17
Economic Indicators Based on EIA High Oil Price Case

	2005	2010	2015	2020	2025	2030	Annual Change 2005-2030
Gross Domestic Product (billion '05$)	12,503	14,509	16,772	19,595	22,546	25,860	2.9%
Consumption	8,814	10,140	11,491	13,226	15,045	16,974	2.7%
Investment	2,159	2,508	3,042	3,706	4,507	5,512	3.8%
Government Spending	2,229	2,410	2,578	2,775	2,968	3,205	1.5%
Exports	1,351	2,025	2,917	4,138	5,621	7,583	7.1%
Imports	2,054	2,541	3,127	3,947	5,030	6,434	4.7%
Energy Intensity (tbtu/'05$GDP)	8.04	7.32	6.63	5.98	5.48	5.03	-1.9%
GDP Price Index ('05=100)	100	111	125	142	159	179	2.3%
CPI - All-Urban ('05=100)	100	112	129	149	170	194	2.7%
Energy Commodities and Services	100	109	135	158	182	214	3.1%
WPI ('05=100)	100	104	114	125	135	147	1.6%
Fuel and Power	100	107	129	154	180	217	3.2%
Federal Funds Rate (%)	3.24	5.20	5.14	4.80	4.64	4.69	-
10-Year Treasury Note Rate (%)	4.43	5.99	6.07	6.02	5.97	6.05	-
AA Utility Bond Rate (%)	5.64	7.64	7.77	8.16	8.38	8.56	-
Value of Shipments (billion '05$)	6,466	7,012	7,730	8,610	9,602	10,746	2.1%
Non-Manufacturing	1,667	1,744	1,894	2,056	2,204	2,360	1.4%
Manufacturing	4,800	5,268	5,836	6,554	7,398	8,386	2.3%
Population (millions)	297	310	324	337	351	365	0.8%
Labor Force (millions)	149	159	163	167	173	181	0.8%
Total Nonfarm Employment (millions)	134	141	147	156	165	174	1.1%
Employment, Manufacturing	14	14	13	13	13	13	-0.5%
Nonfarm Labor Productivity ('05=100)	100	111	126	140	157	175	2.3%
Unemployment Rate (percent)	5.1	5.1	5.0	4.6	4.8	4.9	-
Disposable Personal Income (billion'05$)	9,235	10,732	12,244	14,453	16,797	19,367	3.0%
Housing Starts (millions)	2.16	1.92	1.93	1.90	1.84	1.81	-0.7%
Commercial Floorspace (billion sq. ft.)	76.2	82.2	88.5	95.4	103.0	111.3	1.5%
Unit Sales of Light-Duty Vehicles (millions)	16.9	17.1	17.6	18.6	20.2	21.4	0.9%
Imported Crude Oil Price ('04$)	49.70	58.99	71.98	79.98	84.98	89.98	2.4%
Low Sulfur Light	55.93	62.65	76.30	85.06	90.27	95.71	2.2%

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2006*, and Management Information Services, Inc., 2006.

The feasible liquid fuels alternatives were assessed on the basis of three criteria:

- Is the option in question currently available or nearly available both technologically and economically? Thus, if the U.S. had to initiate a crash program in 2007, would this be a viable commercial option?

- How much would it realistically cost to drastically and quickly ramp up production – for the supply options, or to implement demand reductions – for the efficiency options? The requirement involves production of millions of barrels per day of substitute liquid fuels. Is fuels production or savings of this magnitude possible from the option?
- How long will it take for the option to make a meaningful contribution? It must be recognized that some options, such as coal-to-liquids, are currently feasible, while others, such as oil shale and biomass, may require additional R, D, & D.

On the demand side, Scenario 1 assumed that, coincident with the crash substitute fuels program, transportation fuel efficiency policies will also be initiated. No specific enhanced vehicle fuel efficiency requirements were hypothesized. Rather, the generic gains likely from transportation efficiency programs were projected, and these reduced forecast overall U.S. petroleum requirements. Mass transit, rail, and light rail initiatives were part of the demand side program.

The basic findings for Scenario 1 are described in Sections VI.A., VI.B, and VI.C, above.

Scenario 2: Oil peaking in 2010, But no AES Initiatives

This scenario assumed that, even though world oil peaking occurs within four years, the AES program is not initiated.

Scenario 2 considered the case where the worldwide demand for oil begins to exceed the supply of conventional, relatively cheap oil (the peaking of conventional oil) in 2010 and that no U.S. substitute fuels initiatives have been undertaken. This is essentially a static policy scenario where U.S. energy policy continues to drift for the remainder of the decade.

Consideration of this scenario is necessary for several reasons:

- First, as noted, this is current U.S. policy and may continue for the foreseeable future until a major liquid fuels crisis occurs.
- Second, it represents a "worst case" scenario and demonstrates the potential dangers of not implementing the AES initiatives.
- Third, the implications of this scenario were compared and contrasted with the benefits of initiating the AES program in 2007.
- Fourth, this scenario demonstrates that, if peaking were to occur as early as 2010, then aggressive mitigation programs have to be initiated immediately.

Under this scenario, U.S. GDP in 2010 is about $14,500 (2005$) and oil prices in 2010 are in the range of $65 - $70/bbl. (2005$). A review of studies conducted over the past two decades indicates that the elasticity of GDP to a sudden doubling of oil prices is between -2 percent to -6.4 percent. We estimated here that the elasticity is -4 percent.

What would likely happen to oil prices if peaking occurs in 2010? At least in the short run they would at least double, and may increase even more. In this scenario we assumed that the immediate effect is that oil prices increase by 150 percent: From about $65 - $70/bbl. to about $165 - $175/bbl. A 150 percent increase in oil prices would decrease 2010 U.S. GDP by about 6 percent -- about $900 billion. This would likely generate the most severe recession since the Great Depression.[1]

The severity of this GDP impact will gradually decrease over time under both Scenario 2 and Scenario 3 (where oil peaking in 2010 is assumed in conjunction with implementation of the AES initiatives in 2007, as discussed below) as supply and demand adjustments are made. In the short run, almost all of the adjustment would be "demand destruction" in both scenarios. In the longer run, this would be mitigated considerably in Scenario 3 because the AES initiatives are already in place and would be producing and saving more and more liquid fuel each year. Adjustment would be longer and more painful under Scenario 2 because it assumes that no AES initiative would be implemented. Further, under this scenario, by definition, more of the adjustment would have to be through demand destruction.

We estimated that under scenario 2, the $900 billion 2010 reduction in GDP would gradually decline over the decade until by 2020 it is $450 billion below what it would have been otherwise. By 2020, even in this case, in addition to demand destruction some additional alternative liquid fuel supplies are being produced driven by market conditions.

Scenario 3: The AES Initiatives With Oil Peaking in 2010

Scenario 3 assumes that oil peaking and supply shortfalls occur in 2010 and that, beginning in 2007, the AES initiates are implemented. Thus, Scenario 3 also considers the case where the worldwide demand for oil begins to exceed the supply of conventional, relatively cheap oil in about 2010. However, this scenario assumes that the AES initiatives are implemented beginning in 2007. The precise parameters, technical specifications, and magnitude of the AES program are similar to those specified in Scenario 1, and result in a rapid build-up of plants producing significant amounts of substitute liquid fuels within a decade. This scenario also includes the effects of the generic transportation fuel efficiency initiatives.

[1]This may be a conservative estimate of the potential impact. The Oil Shockwave exercise conducted in September 2005 by members of Congress and former senior government officials found that the U.S. is highly vulnerable to oil shocks resulting from the withdrawal of even relatively small amounts of oil from the global market. It found that even the temporary loss of only four percent of oil in the international market could cause oil prices to more than double and cause a severe recession in the U.S. See *Oil Shockwave Report*, National Commission on Energy Policy, Washington, D.C., September 2005.

Under scenario 3, the initial reduction in GDP in 2010 would be almost as large as in scenario 2, since relatively little alternate liquid fuels will be produced in 2010. However, two factors will decrease the initial GDP losses under Scenario 3:

- First, since the AES initiatives began in 2007, by 2010 a small amount of liquid fuels will be produced and saved – about 1.1 MM bpd. This will help to lessen the initial decrease in GDP resulting from oil peaking in that year.
- Second, the investments in the AES initiatives in 2010 will be ramping up and will tend to slightly increase GDP above what it would have been in the absence of these initiatives.

Both factors will tend to mitigate the negative impacts on GDP in 2010 under Scenario 3. While in 2010 these positive impacts on GDP and employment will be relatively small compared to the negative impacts caused by oil peaking, they will be substantial and beneficial. We estimate that the initial GDP reduction in 2010 under Scenario 3 is about $720 billion. Most important, the beneficial impacts under Scenario 3 will increase every year after 2010 as the AES initiatives ramp up.

The results of this scenario can be contrasted with those of Scenario 2 to demonstrate the energy and economic implications of not implementing the AES initiatives if oil peaks as early as 2010. If fact, since all of the mitigation programs involve several years start-up time, this scenario shows that, if oil is likely to peak in 2010, it is absolutely necessary to initiate crash mitigation programs immediately. Even then, the situation over the next decade is likely to be troublesome.

Comparison of Scenarios 2 and 3

Table VI-18 summarizes the economic impacts under Scenarios 2 and 3. These are discussed below.

Under Scenario 2, the initial decrease in GDP in 2010 is severe and long-lasting and continues through the end of the decade. There are similar negative effects on jobs, tax revenues, and other economic variables for the entire decade. The total cumulative loss in GDP over the period 2010 – 2020 is about $7.3 trillion. After 2020, there is continuing, though declining GDP loss. Under Scenario 2:

In 2010:

- GDP loss totals about $900 billion
- GDP in 2010 is 6.2 percent lower than in the base case
- The number of unemployed in 2010 increases by 8.3 million.
- The unemployment rate in 2010 is 11 percent
- Federal, state, and local government tax revenues decrease by $275 billion

In 2015:

- GDP loss totals about $650 billion
- GDP is 3.9 percent lower
- The number of unemployed in 2015 increases by 6.1 million.
- The unemployment rate is 8.7 percent
- Federal, state, and local government tax revenues decrease by $190 billion

Table VI-18
Summary of the Economic Impacts of Scenario 2 and Scenario 3

	Scenario 2	**Scenario 3**
	2010	
GDP	-$900 billion	-$720 billion
GDP percent	-6.2 percent	-5 percent
Incremental job impacts	-8.3 million	-6.2 million
Unemployment rate	11%	9%
Federal, state, & local government tax revenues	-$275 billion	-$210 billion
	2015	
GDP	-$650 billion	-$265 billion
GDP percent	-3.9 percent	-1.6 percent
Incremental job impacts	-6.1 million	-1.9 million
Unemployment rate	8.7%	6.2%
Federal, state, & local government tax revenues	-$190 billion	-$80 billion
	2020	
GDP	-$450 billion	+$200 billion
GDP percent	-2.3 percent	+1 percent
Incremental job impacts	-4.2 million	+0.9 million
Unemployment rate	6.7%	4.1%
Federal, state, & local government tax revenues	-$140 billion	+$60 billion

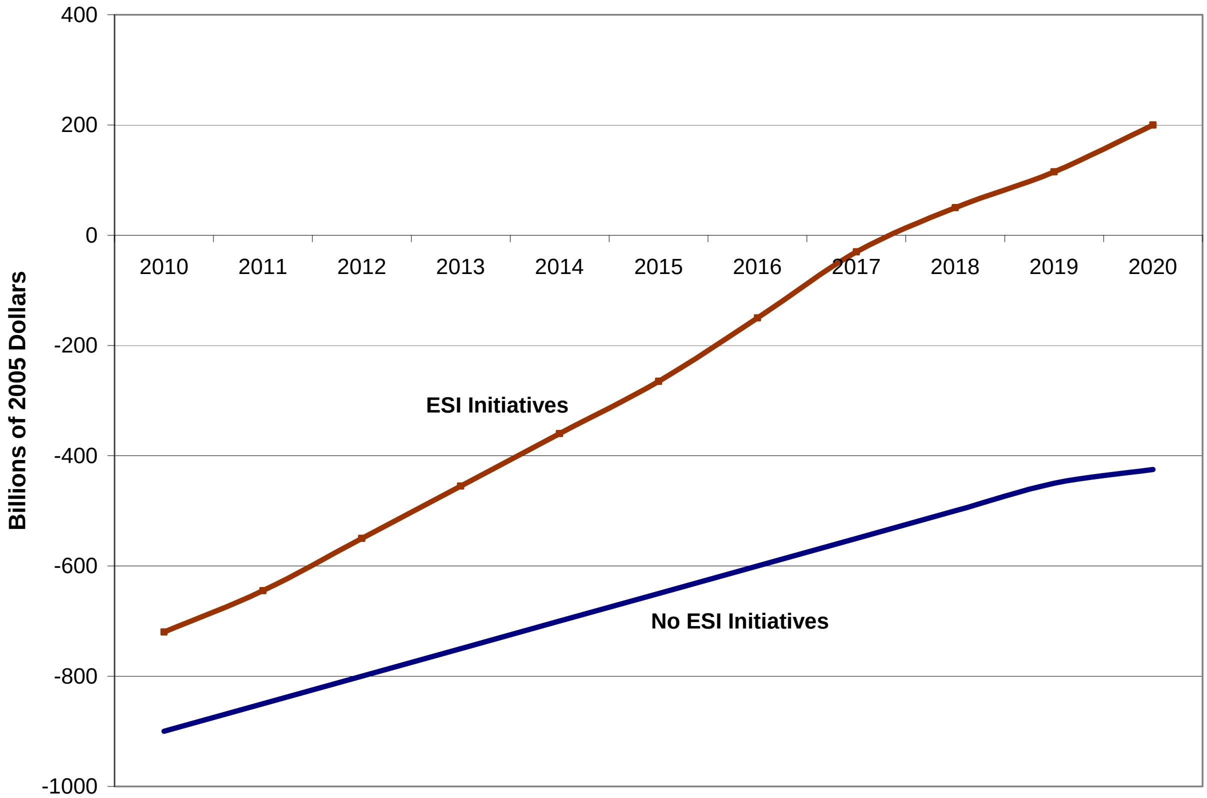
Source: Southern States Energy Board and Management Information Services, Inc., 2006.

In 2020:

- GDP loss totals about $450 billion
- GDP is 2.3 percent lower
- The number of unemployed in 2020 increases by 4.2 million.
- The unemployment rate is 6.7 percent
- Federal, state, and local government tax revenues decrease by $140 billion

Under scenario 3, the total cumulative loss in GDP over the period 2010 – 2020 is about \$2.7 trillion. After 2017, the GDP impacts of this scenario are positive (see Figure VI-9), as the combined impacts of U.S. domestic liquid fuels production and AES investments begin to out weigh the negative economic impacts of oil peaking.

Figure VI-10
GDP Changes Under Scenarios 2 and 3



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

In 2010:

- GDP loss totals about \$720 billion
- GDP is 5 percent lower than in the base case
- The number of unemployed increases by 6.2 million.
- The unemployment rate is 9 percent
- Federal, state, and local government tax revenues decrease by \$210 billion

In 2015:

- GDP loss totals about \$265 billion
- GDP is 1.6 percent lower

- The number of unemployed increases by 1.9 million.
- The unemployment rate is 6.2 percent
- Federal, state, and local government tax revenues decrease by $80 billion

In 2020:

- GDP increases by $200 billion
- GDP is 0.9 percent higher than in the base case
- The number of unemployed in 2015 decreases by 900 thousand.
- The unemployment rate in 2015 is 4.1 percent – compared to 4.6 percent in the base case
- Federal, state, and local government tax revenues increases by $60 billion

Thus, under Scenario 3, in 2020 GDP, employment, and tax revenues actually increase.

Comparative Impacts of Scenarios 2 and 3

Assuming that oil peaks in 2010, over the period 2010-2020 implementing the SSEB AES initiatives on a crash basis beginning in 2007 will save the U.S. economy:

- $4.6 trillion in GDP
- 40 million job years of employment
- $1.3 billion in federal, state, and local government tax revenues.

Under Scenario 3, by 2020 GDP is 3.3 percent higher than under Scenario 2 and almost one percent higher than it would have been if oil had not peaked in 2010. The reason is that because by 2010 the AES initiatives are producing/saving about 43 percent of U.S. oil imports and the AES investments themselves are increasing industry sales by nearly $200 billion. Therefore, we estimate that this oil import replacement and investment, along with other market-driven adjustments, will result in a GDP in 2020 nearly one percent higher than it would have been otherwise.

Further, after 2020, in scenario 2 (where the AES initiatives have not been implemented), further losses in GDP, employment, and tax revenues continue to accrue. In scenario 3, this is not the case. In fact, in this case, U.S. GDP, employment and tax revenues are actually higher than in the base case, and this continues to be true after 2020.

Implications

There are several major implications of these findings.

First, if oil peaks in 2010, there is little that can be done to avoid the serious short term economic impacts. Even starting the SSEB AES initiatives in 2007 will not result in enough liquid fuel production and saving in 2010 to avoid most of the economic damage in that year and in the years immediately following 2010. While it is moot to recommend that these initiatives should have been begun in 1997 instead of 2007, it is certainly imperative that these initiatives be implemented no later than next year.

Second, while the AES initiatives will not be able to prevent most of the economic damage occurring in 2010 from oil peaking, they will substantially lessen the subsequent adverse impacts over the decade, and will reverse them by 2017. By the end of the decade they will have more than alleviated the adverse impacts on GDP and employment, as well as making the U.S. substantially more energy secure.

Third, the danger to waiting or delaying the implementation of the initiatives is serious and delay must be avoided. For example, if the "problem" is not recognized until oil peaking occurred in 2010, and legislation is not enacted until 2011, the incremental cumulative economic damage over the coming decade would be severe.

Finally, the estimates here, if anything, err on the conservative side. Oil peaking in 2010 could lead to a decade or more of severe oil shortages, huge price increases, and greatly enhanced oil price volatility which could have much more dire economic consequences for the U.S. than we estimated. The estimates derived here are conservative for several reasons:

- We assumed that the decline in conventional oil production after peaking is two percent per year. Many petroleum geologists contend that the decline rate could be substantially higher than this.
- We assumed that at oil peaking, oil prices would immediately increase about 150 percent, and many oil market specialists contend that at oil peaking oil prices may increase much more than this.
- We assumed that the elasticity of GDP with respect to oil price increases is -4 percent, but estimates range as high as -6.4 percent

It is thus possible that the economic consequences could be twice as severe as estimated here. If this is the case, then, assuming oil peaking in 2010, the economic benefits of implementing AES programs in 2007 compared to not implementing them could, over the decade, total:

- $9 trillion in GDP
- 80 million job years of employment
- $2.5 trillion in federal, state, and local government tax revenues.

Impacts of the AES Initiatives Relative to Oil Peaking-Induced Supply Shortfalls

If oil peaks in 2010, conventional oil production is likely to decrease worldwide by at least two percent annually, and it is unlikely that the U.S. would be able to avoid reductions in the amount of oil available. We estimated how the liquid fuels produced and saved by AES initiatives compare to this conventional oil "shortfall," as shown in Table VI-19. The "oil peaking" column estimates the conventional U.S. oil shortfall, beginning in 2011. The data in the "no oil peaking" column gives U.S. oil requirements under the baseline scenario assuming no oil peaking, and the difference is the estimated U.S. oil supply shortfall resulting from oil peaking. The final column shows the annual contributions from the AES initiatives.

Table VI-19
Impact of AES Initiatives Relative to U.S. Oil Supply Decline After Oil Peaking in 2010
(Millions of barrels/day of oil)

	Oil Peaking	No Oil Peaking	Difference	AES Impact
2010	22.0	22.0	--	1.1
2011	21.6	22.3	0.7	1.5
2012	21.1	22.6	1.5	1.9
2013	20.7	22.9	2.2	2.5
2014	20.3	23.2	2.9	3.1
2015	19.9	23.5	3.6	3.7
2016	19.5	23.8	4.3	4.4
2017	19.1	24.1	5.0	5.3
2018	18.7	24.3	5.6	6.2
2019	18.3	24.6	6.3	7.5
2020	18.0	25.0	7.0	8.4
2021	17.6	25.3	7.7	9.3
2022	17.3	25.5	8.2	10.3
2023	16.9	25.8	8.9	11.1
2024	16.6	26.1	9.5	12.2
2025	16.3	26.4	10.1	13.3
2026	15.9	26.6	10.7	14.3
2027	15.6	26.9	11.3	15.5
2028	15.3	27.2	11.9	16.6
2029	15.0	27.4	12.4	17.7
2030	14.7	27.6	12.9	18.9

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

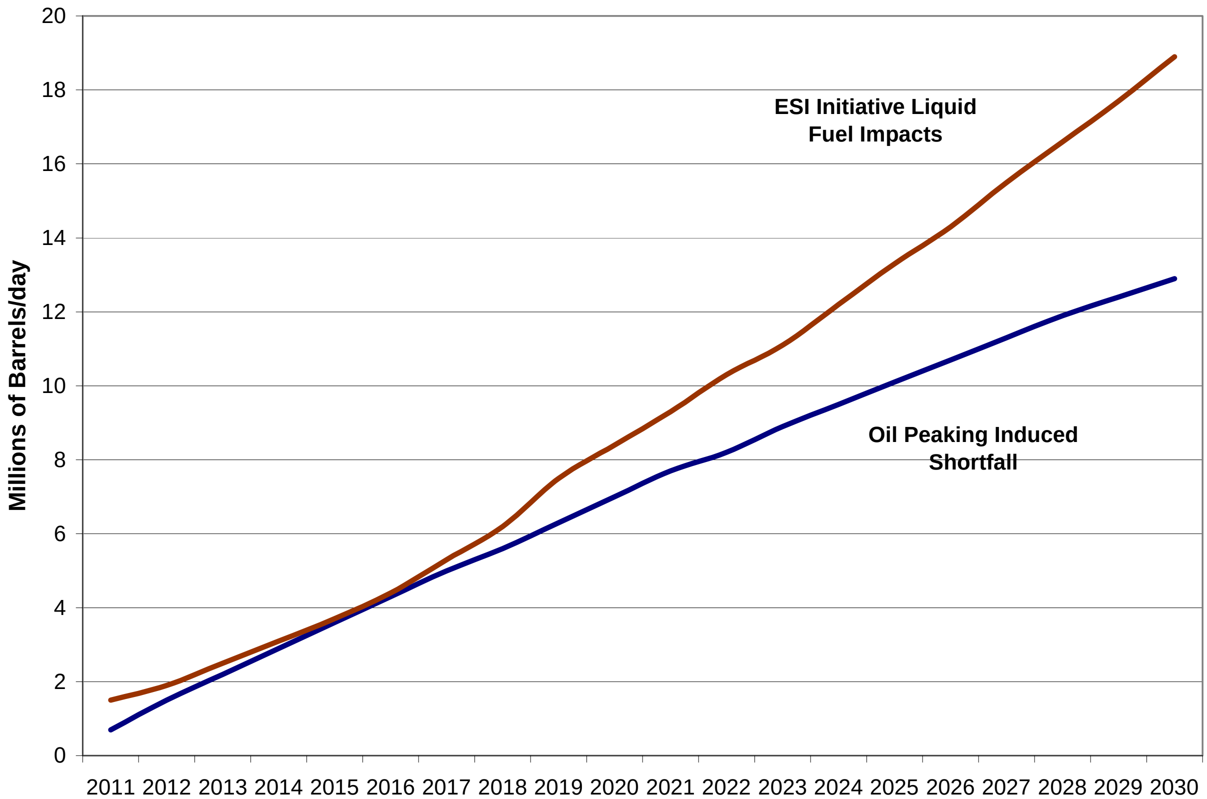
This table and Figure VI-10 show that, assuming oil peaking in 2010, the AES initiatives produce or save enough liquid fuels to about replace the estimated shortfall through 2016. After that, however, the impacts of the AES initiatives increasingly exceed the shortfall every year:

- By 2020, the impact of the AES initiatives is 20 percent greater than the oil shortfall
- By 2025, the impact of the AES initiatives is 32 percent greater than the oil shortfall

- By 2030, the impact of the AES initiatives is 47 percent greater than the oil shortfall

It is thus clear that, if the AES initiatives are implemented on a crash basis beginning in 2007, they can produce and save more than sufficient amounts of liquid fuels to replace the U.S. shortfalls likely to result from oil peaking in 2010. However, this is only true if the initiatives are begun next year. Once again, it is imperative that any delays in implementation be avoided.

Figure VI-11
Impact of AES Initiatives in Replacing U.S. Oil Supply Decline
After Oil Peaking in 2010
(millions of barrels/day of oil)



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Scenario 4: The AES Initiatives With Oil Peaking in 2020

Scenario 4 assumes that oil peaking and supply shortfalls occur in 2020 and that the AES initiatives are implemented, beginning in 2007. Thus, Scenario 4 considers the case where the worldwide demand for oil begins to exceed the supply of conventional, relatively cheap oil in 2020. However, this scenario assumes that the AES program is initiated in 2007 – 13 years prior to the peak. The precise parameters, technical specifications, and magnitude of the AES initiatives are similar to those specified in Scenario 1, and result in a rapid build-up of plants producing significant amounts of substitute liquid fuels within a decade. This scenario also includes the effects of the generic transportation fuel efficiency initiatives.

This scenario demonstrates that, if oil peaking is delayed until 2020 and if aggressive mitigation programs are initiated in 2007, the economic and national security problems resulting from oil peaking can be minimized. The results from this scenario can be compared with those of the baseline case and the other scenarios.

Under this scenario, U.S. GDP in 2010 is about $19,600 (2005$) and oil prices in 2010 are in the range of $80 - $90/bbl. (2005$). As noted, review of studies conducted over the past two decades indicates that the elasticity of GDP to a sudden doubling of oil prices is between -2 percent to -6.4 percent. We estimated here that the elasticity is -4 percent.

What would happen to oil prices if peaking occurs in 2020? At least in the short run they would at least double, and may increase even more. We assume that the immediate effect is that oil prices increase by 150 percent: From about $80 - $90/bbl. to about $200 - $225/bbl (2005 dollars). A 150 percent increase in oil prices would decrease 2020 U.S. GDP by about 6 percent -- about $1.2 trillion. Under the baseline case, which assumes no mitigation options, this would likely generate the most severe recession since the Great Depression.

The severity of this GDP impact will gradually decrease over time under both Scenario 4 and under the Baseline Scenario with oil peaking in 2020 -- where the AES initiatives have not been implemented, as supply and demand adjustments are made. In the short run, under the Baseline case, almost all of the adjustment would be "demand destruction." However, this would be largely mitigated in Scenario 4 because the AES initiatives would have already been in place since 2007 and would be producing and saving very large amounts of liquid fuel each year and providing significant economic stimulus to the economy. Adjustment would be much longer and much more painful under the Baseline Scenario with oil peaking in 2020 because it assumes that no AES initiatives would be implemented. Further, under this scenario, by definition, most of the adjustment would have to be through demand destruction.

Therefore, we estimate that under the Baseline Scenario with oil peaking in 2020, the $1.2 trillion 2020 reduction in GDP would gradually decline over the decade until by 2030 GDP is about $600 billion below what it would have been otherwise. By 2030, even in this case, in addition to demand destruction some additional alternative liquid fuel supplies are being produced driven by market conditions.

Under Scenario 4, the initial reduction in GDP in 2020 would be much less than under the base case, for two reasons:

- First, since the AES initiatives began in 2007, by 2020 a large amount of liquid fuels will be produced and saved – about 8.4 MM bpd, about 43 percent of U.S. oil imports. This will greatly lessen the initial impact on GDP resulting from oil peaking in that year.
- Second, the investments in the AES initiatives in 2020 will be substantial and will continue to ramp up, and will increase GDP above what it would have been in the absence of these initiatives.

The initial impact on GDP in 2020 under Scenario 4 will still be negative because, even with the AES initiatives, the U.S. is still importing more than half of its oil. The greatly increased oil prices under oil peaking will thus still negatively affect the U.S. economy. However, in this case much of the increased revenues from higher oil prices is being received by domestic producers. Every year after 2020, U.S. substitute liquid fuels production increases rapidly, and this – in conjunction with the stimulative effects of the AES investments – will reduce the negative impacts on U.S. GDP. Table VI-20 summarizes the economic impacts under Scenario 4 compared to the base case. These are discussed below.

Table VI-20
Summary of the Economic Impacts of Oil Peaking in 2020

	Base Case With no Mitigation	Scenario 4
	2020	
GDP	-$1.2 trillion	-$200 billion
GDP percent	-6.1 percent	-1 percent
Incremental job impacts	-8.6 million	-1.4 million
Unemployment rate	10%	5.5%
Federal, state, & local government tax revenues	-$350 billion	-$60 billion
	2025	
GDP	-$900 billion	+$250 billion
GDP percent	-4 percent	+1.2 percent
Incremental job impacts	-6.3 million	+1.8 million
Unemployment rate	8.5%	3.8%
Federal, state, & local government tax revenues	-$280 billion	+$80 billion
	2030	
GDP	-$600 billion	+$800 billion
GDP percent	-2.4 percent	+3.1 percent
Incremental job impacts	-4.3 million	+5.6 million
Unemployment rate	7.3%	3%
Federal, state, & local government tax revenues	-$190 billion	+$250 billion

Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Both factors will minimize the adverse GDP impact in 2020 under Scenario 4. By 2020 the positive impacts on GDP and employment will be substantial compared to the negative impacts caused by oil peaking. We estimate that the initial GDP reduction in

2020 under Scenario 4 is about $300 billion. Most important, the beneficial impacts under Scenario 4 will increase every year after 2020 as the AES initiatives continue to ramp up.

Base Case With Oil Peaking in 2020

If oil peaks in 2020, under the base case (which includes no crash mitigation initiatives), the initial decrease in GDP in 2020 is severe and long-lasting and continues through the end of the decade. There are similar negative effects on jobs and on tax revenues for the entire decade. The total cumulative loss in GDP over the period 2020 – 2030 is nearly $10 trillion. After 2030, there is continuing, though declining GDP losses.

In 2020:

- GDP loss totals about $1.2 trillion
- GDP is 6.1 percent lower than in the base case assuming no oil peaking
- The number of unemployed increases by 8.6 million.
- The unemployment rate is 10 percent
- Federal, state, and local government tax revenues decrease by $350 billion

In 2025:

- GDP loss totals about $900 billion
- GDP is 4 percent lower
- The number of unemployed increases by 6.3 million.
- The unemployment rate is 8.5 percent
- Federal, state, and local government tax revenues decrease by $280 billion

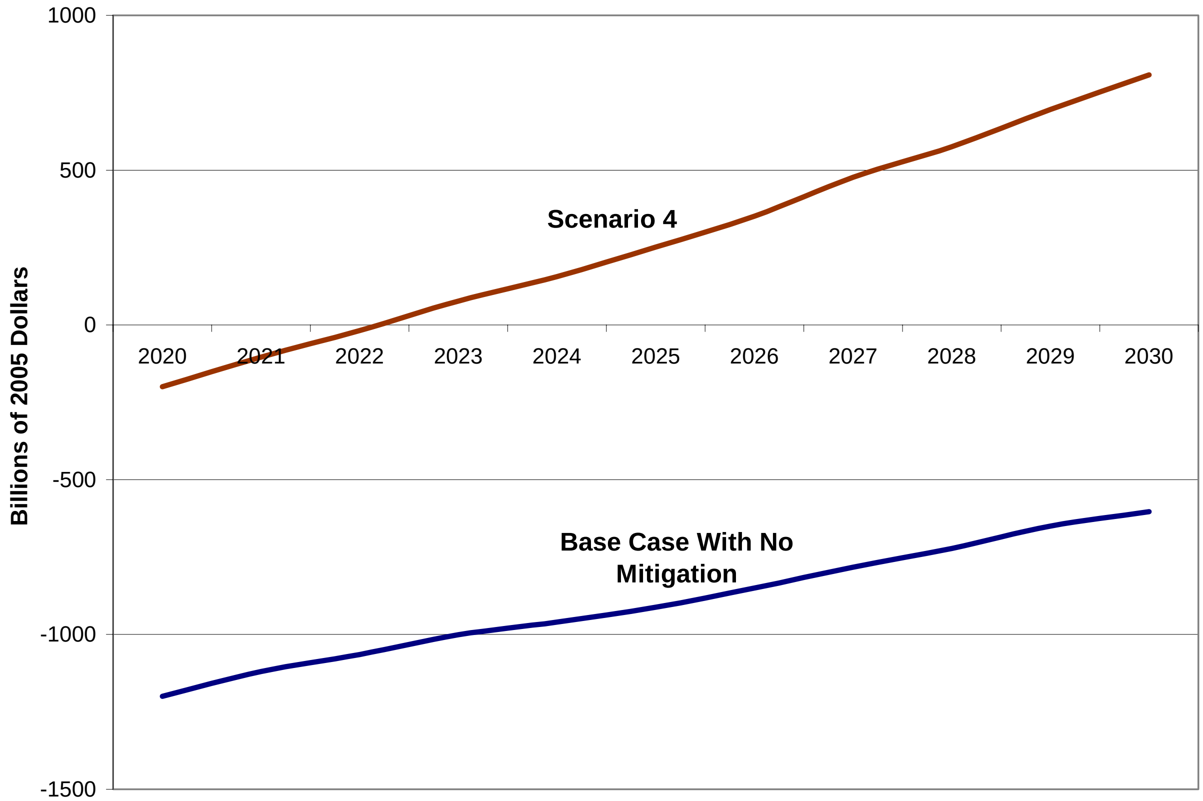
In 2030:

- GDP loss totals about $600 billion
- GDP is 2.4 percent lower
- The number of unemployed increases by 4.3 million.
- The unemployment rate is 7.3 percent
- Federal, state, and local government tax revenues decrease by $190 billion

Scenario 4

Under scenario 4, the total cumulative gain (compared to the base case) in GDP over the period 2020 – 2030 is about $ 13 trillion. After 2022, the GDP impacts of this scenario are positive (see Figure VI-11), as the combined impacts of U.S. domestic liquid fuels production and AES investments outweigh the negative economic impacts of oil peaking.

Figure VI-12
GDP Changes Under Scenario 4



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

In 2020:

- GDP loss totals about $200 billion
- GDP is one percent lower than in the base case
- The number of unemployed increases by 1.4 million.
- The unemployment rate is 5.5 percent
- Federal, state, and local government tax revenues decrease by $60 billion

In 2025:

- GDP increases by $250 billion
- GDP is 1.2 percent higher than in the base case
- The number of unemployed decreases by 1.8 million.

- The unemployment rate is 3.8 percent
- Federal, state, and local government tax revenues increases by $80 billion

In 2030:

- GDP increases by $800 billion
- GDP is 3.1 percent higher than in the base case
- The number of unemployed decreases by 5.6 million.
- The unemployment rate is three percent
- Federal, state, and local government tax revenues increases by $250 billion

Thus, under Scenario 3, in 2025 and 2030 GDP, employment, and tax revenues increase substantially.

Comparative Impacts of Scenario 4

Assuming that oil peaks in 2020, over the period 2020-2030 implementing the SSEB AES initiatives on a crash basis beginning in 2007 will save the U.S. economy (compared to not implementing them):

- $13 trillion in GDP
- 100 million job years of employment
- $4 trillion in federal, state, and local government tax revenues.

Under Scenario 4, by 2030 GDP is eight percent higher than it would be if the AES initiatives had not been implemented (see Figure V-11. The reason is that because by 2030 the AES initiatives are producing/saving about 100 percent of U.S. oil imports and the AES investments themselves are increasing industry sales by one-third of a trillion dollars. Therefore, we estimate that this oil import replacement and investment, along with other market-driven adjustments, will more than offset the negative economic effects of oil peaking in 2020.

Further, after 2030, assuming that the AES initiatives have not been implemented, further losses in GDP, employment, and tax revenues continue to accrue. In scenario 4, this is not the case. In fact, in this case, U.S. GDP, employment and tax revenues continue to increase after 2030.

Implications

There are several major implications of these findings.

First, if oil peaks in 2020, most of the serious short term negative economic impacts can be avoided if the AES initiatives are begun in 2007. Starting the SSEB AES initiatives in 2007 will result in sufficient liquid fuel production and saving in 2020 to minimize most of the economic damage in that year and in the years immediately following. In fact, by about 2023, the relative economic damage to the U.S. economy will be minimal. However, this fortunate result holds true only if the AES program is implemented no later than next year.

Second, the AES initiatives will be able to minimize most of the economic damage occurring in 2020 from oil peaking and will eliminate the subsequent adverse impacts over the decade – reversing them by 2023. By the end of the decade they will have more than alleviated the adverse impacts on GDP and employment, as well as making the U.S. essentially energy secure and independent.

Third, the danger to waiting or delaying the implementation of the initiatives is serious and delay must be avoided. For example, if the "problem" is not recognized until oil peaking occurred in 2020, and legislation is not enacted until 2021, the incremental cumulative economic damage over the coming decade would be extremely severe and have dire economic consequences.

Finally, the estimates here, if anything, err on the conservative side. Oil peaking in 2020 could lead to a decade or more of severe oil shortages, huge price increases, and greatly enhanced oil price volatility which could have much more dire economic consequences for the U.S. than we estimated. As discussed, the estimates derived here are conservative for several reasons:

- We assumed that the decline in conventional oil production after peaking is two percent per year, and it could be higher than this.
- We assumed that at oil peaking, oil prices would immediately increase about 150 percent, and they may increase much more than this.
- We assumed that the elasticity of GDP with respect to oil price increases is -4 percent, but estimates range as high as -6.4 percent

It is thus possible that the economic consequences could be twice as severe as estimated here. If this is the case, then, assuming oil peaking in 2020, the economic benefits of implementing AES programs in 2007 compared to not implementing them, could over the decade 2020-2030 total:

- $25 trillion in GDP
- 200 million job years of employment
- $8 trillion in federal, state, and local government tax revenues.

Impacts of the AES Initiatives Relative to Oil Peaking-Induced Supply Shortfalls

If oil peaks in 2020, conventional oil production is likely to decrease worldwide by about two percent annually, and it is unlikely that the U.S. would be able to avoid reductions in the amount of oil available. We estimated how the liquid fuels produced and saved by AES initiatives compare to this conventional oil "shortfall," as shown in

Table VI-21. The "oil peaking" column estimates the conventional U.S. oil shortfall, beginning in 2021. The data in the "no oil peaking" column gives U.S. oil requirements under the base case assuming no oil peaking, and the difference is the estimated U.S. oil supply shortfall resulting from oil peaking. The final column shows the annual contributions from the AES initiatives.

This table and Figure VI-12 show that, assuming oil peaking in 2020, the AES initiatives (begun in 2007) produce or save enough liquid fuels to replace several times over the estimated shortfall through 2030. After that the impacts of the AES initiatives continue to exceed the shortfall every year:

- By 2025, the impact of the AES initiatives is 3.5 times greater (9.5 MM bpd) than the oil shortfall.
- By 2030, the impact of the AES initiatives is 2.6 times greater (11.7 MM bpd) than the oil shortfall.

It is thus clear that, if the AES initiatives are implemented on a crash basis beginning in 2007, they can produce and save more than sufficient amounts of liquid fuels to replace the U.S. shortfalls likely to result from oil peaking in 2020. However, this is only true if the initiatives are begun next year. Once again, it is imperative that any delays in implementation be avoided.

Table VI-21
Impact of AES Initiatives Relative to U.S. Oil Supply Decline
After Oil Peaking in 2020
(millions of barrels/day of oil)

	Oil Peaking	No Oil Peaking	Difference	AES Impact
2020	25	25.0	--	8.4
2021	24.5	25.3	0.8	9.3
2022	24.0	25.5	1.5	10.3
2023	23.5	25.8	2.3	11.1
2024	23.1	26.1	3.0	12.2
2025	22.6	26.4	3.8	13.3
2026	22.1	26.6	4.5	14.3
2027	21.7	26.9	5.2	15.5
2028	21.3	27.2	5.9	16.6
2029	20.8	27.4	6.6	17.7
2030	20.4	27.6	7.2	18.9

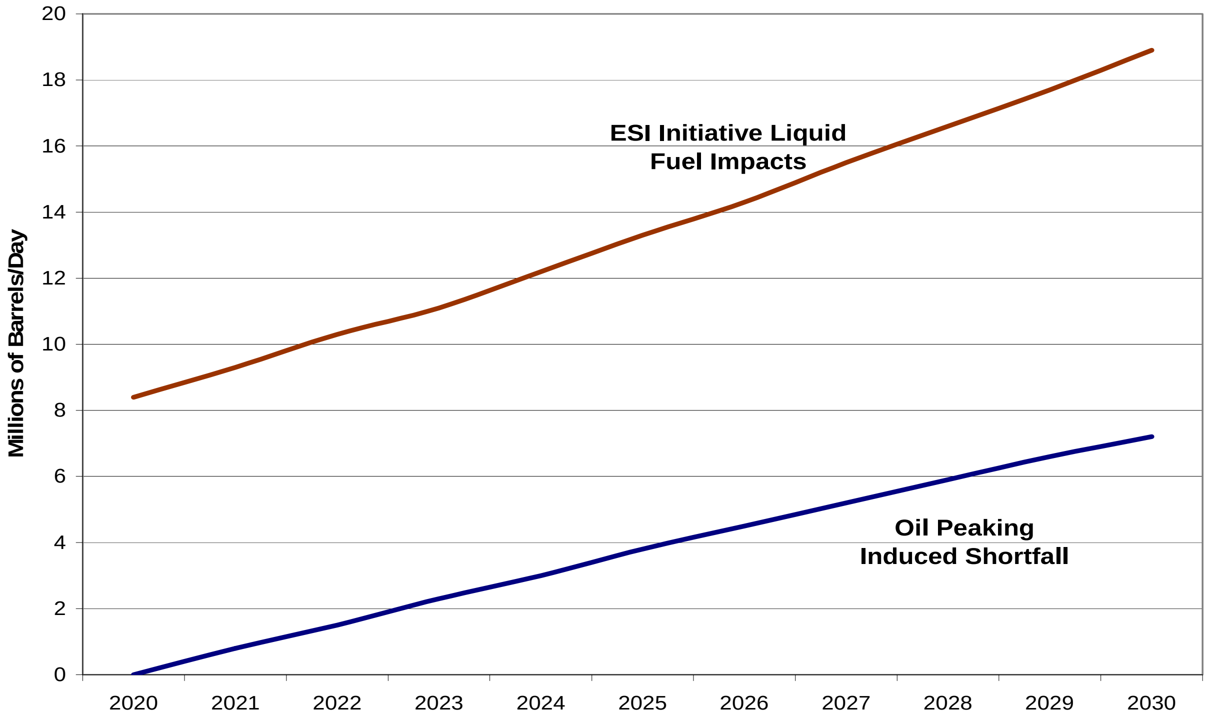
Source: Southern States Energy Board and Management Information Services, Inc., 2006.

VI.E. Reducing U.S. Oil Imports From the Middle East

In his 2006 State of the Union Address, President Bush stated that the nation was "addicted to oil" and he articulated a goal of "reducing U.S. imports of Middle Eastern oil by 75 percent by 2025." Note that the President's stated goal is to ***reduce***

U.S. oil imports from the Middle East by 75 percent; not reduce total U.S. oil imports by 75 percent.

Figure VI-13
Impact of AES Initiatives in Replacing U.S. Oil Supply Decline After Oil Peaking in 2020
(millions of barrels/day of oil)



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

Assessment of this goal was not modeled as a separate scenario. Rather, the results of the AES initiatives were evaluated with respect to their potential impact on reducing U.S. oil imports from the Middle East.

At present, Middle East oil imports account for about 20 percent of total U.S. oil imports, and EIA forecasts that U.S. oil imports in 2025 will total 15.6 mbpd. If we assume that in 2025 20 percent of U.S. exports will still originate in the Middle East, then U.S. oil imports from the Middle East in that year will total about 3 mbpd.

However, most analysts agree that both the U.S. and the world will become increasingly dependent on Middle East oil in the coming decades. Thus, it is likely that, given current policies, U.S. oil imports from the Middle East in 2025 could easily be much greater than 20 percent of the total. For comparison purposes, we hypothetically assume that in 2025 U.S. oil imports from the Middle East are 40 percent of total imports – about 6 mbpd.

Thus, the President's goal of reducing U.S. oil imports from the Middle East by 75 percent by 2025 implies that:

- If U.S. oil imports from the Middle East total 3 mbpd in 2025, a reduction of 2.25 mbpd will be required.
- If U.S. oil imports from the Middle East total 6 mbpd in 2025, a reduction of 4.5 mbpd will be required.

Table VI-3 indicates that, under the SSEB AES initiative, in 2025 the five options combined will produce or save a total of 13.3 mbpd. This would represent:

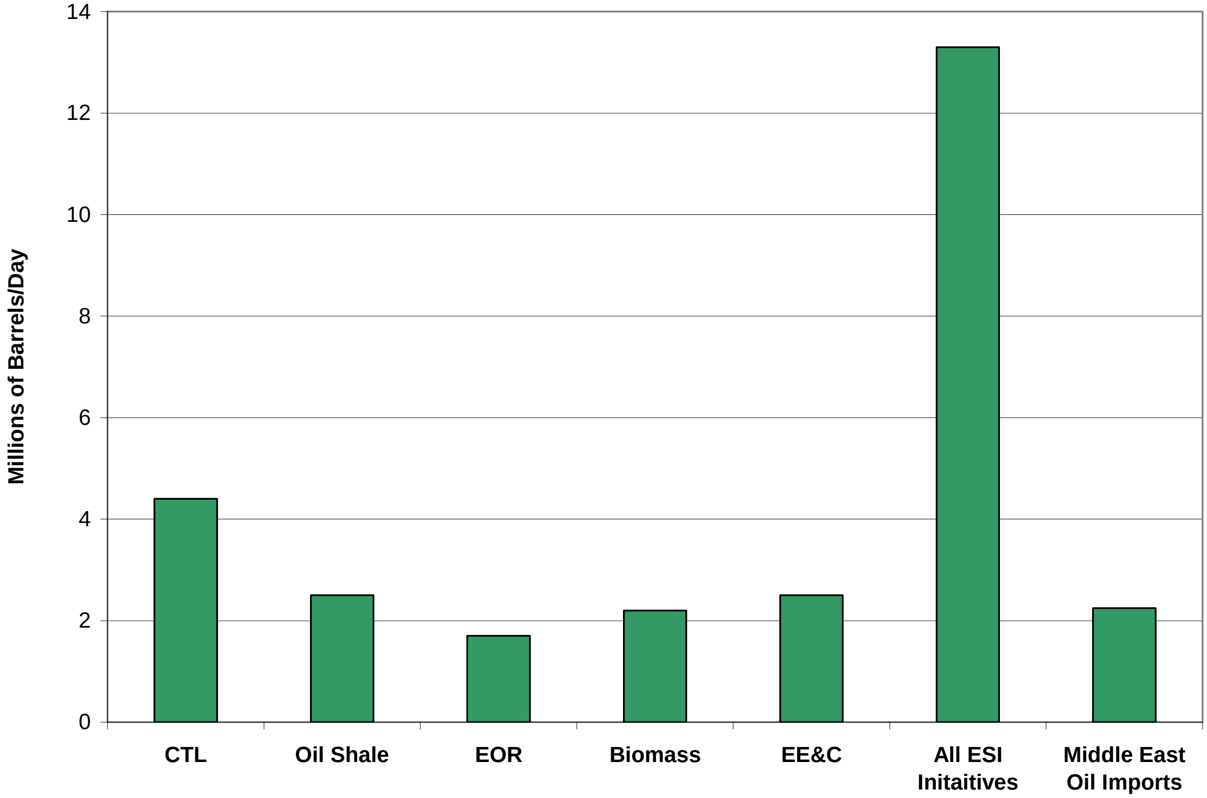
- Six times the amount of oil that the U.S. would be importing from the Middle East if these imports account for 20 percent of total U.S. oil imports.
- Three times the amount of oil that the U.S. would be importing from the Middle East if these imports account for 40 percent of total U.S. oil imports.

Figure VI-13 shows that in 2025 the SSEB AES initiatives will produce or save a total of 13.3 mbpd. This would represent nearly six times the amount of oil that the U.S. would be importing from the Middle East if these imports account for 20 percent of total U.S. oil imports. In fact, one of the options alone – CTL – in 2025 would be providing twice the amount of liquid fuels required to make the U.S. totally independent of oil imports from the Middle East, and each of the other individual AES initiatives themselves would be producing or saving about enough liquid fuels to make the U.S. independent of oil imports from the Middle East.[1]

Thus, our work indicates that the President's goal is feasible if the alternative fuels programs are initiated aggressively and soon – soon being no later than next year. In fact, if these programs are begun in 2007, the President's goal can be exceeded several times over. By 2025, the U.S. will have reduced its oil imports by an amount that is three to six times as large as Middle East oil imports.

[1]In 2025 CTL would be providing enough substitute liquid fuels to make the U.S. totally independent of oil imports from the Middle East even if these imports accounted for 40 percent of total U.S. oil imports.

Figure VI-14
Impact of the AES Initiatives on Reducing U.S. 2025
Oil Imports From the Middle East



Source: Southern States Energy Board and Management Information Services, Inc., 2006.

VII. ENVIRONMENTAL CONSIDERATIONS

VII.A. Emission Reductions and Efficiency

Transitioning from petroleum-based to Fischer Tropsch produced diesel and jet fuel from coal-to-liquids, biomass-to-liquids, and oil shale-to-liquids plants will result in net environmental improvements through reductions in air emissions and improved operational efficiency of diesel and jet engines. FT produced diesel and jet fuels are ultra-clean, biodegradable, and low in particulate matter and are essentially sulfur free. When these fuels are combusted they produce very low particulate and NO_x emissions and essentially zero SO_2 emissions. Cetane for middle distillates is equivalent to octane for gasoline, and the “cetane” rating is the diesel equivalent of the “octane” rating for gasoline performance. FT fuels have a much higher cetane quality than standard petroleum middle distillates and thus burn more efficiently, increasing overall engine performance -- which translates into lower emissions per mile traveled, including CO_2.

In addition to the improved operational efficiencies of this fuel, this study also anticipates that, coincident with the scale-up of alternative fuels programs, engine efficiencies will also increase substantially by 2030. Vehicles and light-duty trucks offer the greatest promise. Following Europe’s lead, a shift to diesel, including Fischer-Tropsch zero sulfur diesel, is anticipated. Diesel vehicles are typically 20 to 50% more fuel efficient than their gasoline counterparts, and diesel hybrids may well double this efficiency advantage.

The following graphics provided by Rentech, Inc., a leading U.S. Fischer-Tropsch technology company, and the U.S. Department of Defense highlight the clear environmental and efficiency advantages of FT diesel. Figure VII-1 shows that FT diesel fuel has a much higher cetane rating than conventional diesel, as well as a substantially reduced emissions profile. Figures VII-1 through VII-4 confirm the environmental benefits of FT fuels.

VII.B. Environmental Considerations Associated with the Production

VII.B.1. Direct Environmental Considerations

Carbon capture and storage

The direct environmental impacts associated with the gasification of coal, biomass, and oil shale into transportation fuels are significantly less than those that result from traditional pulverized coal combustion. Gasification technology, in conjunction with syngas clean-up systems, enables the sulfur and the heavy metals, including mercury contained in the coal, to be removed in forms that are not emitted to the atmosphere and can be further processed into useful products.

Figure VII-1

FT Fuel Comparison Characteristics

	Low Sulfur D-975	California CARB	Rentech (FTD)	EU (2005)	EPA (2006)
Cetane Index	>40	>48	72	>50	>40
Aromatics (vol %)	<35	<10	<4	<10	<35
Sulphur (ppm)	<500	<500†	<1	<10	<15
Biodegradable	NO	NO	YES	NO	NO

† Note: In 2006, US regulations will require <15 ppm sulphur

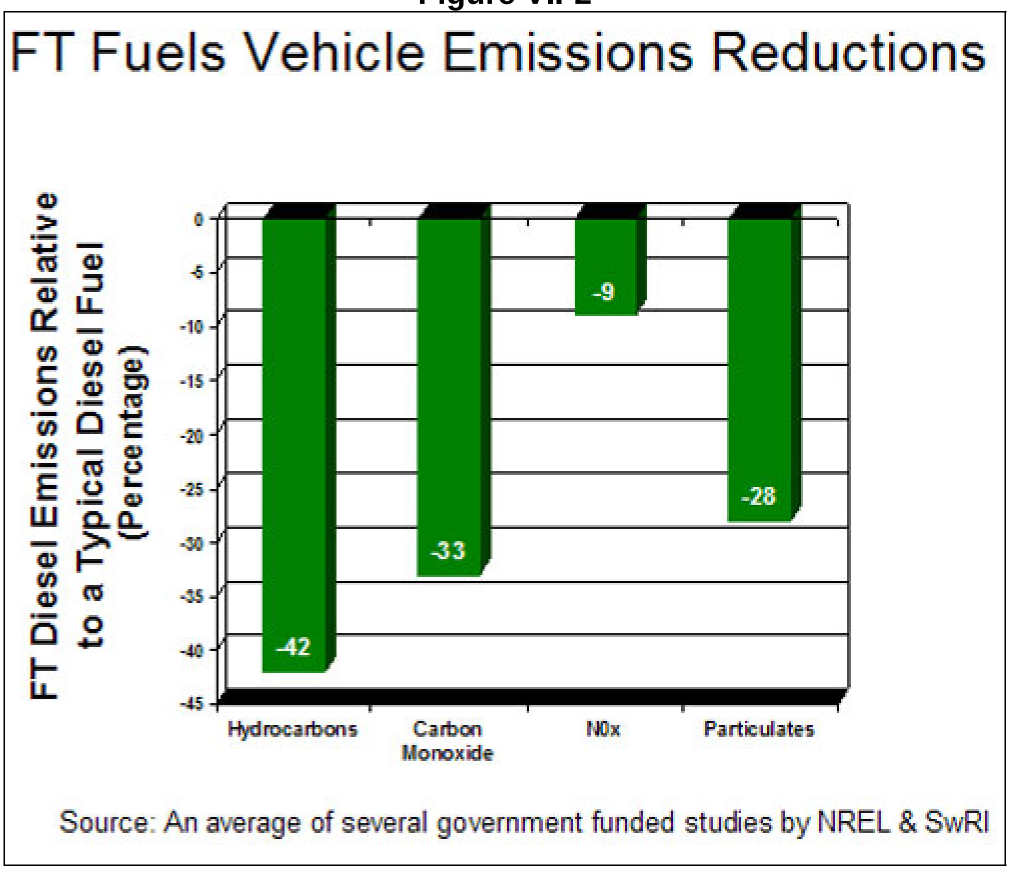
FT Diesel

Conventional Diesel

FTD from coal is an "alternative fuel" under 1992 Energy Policy Act (EPACT)

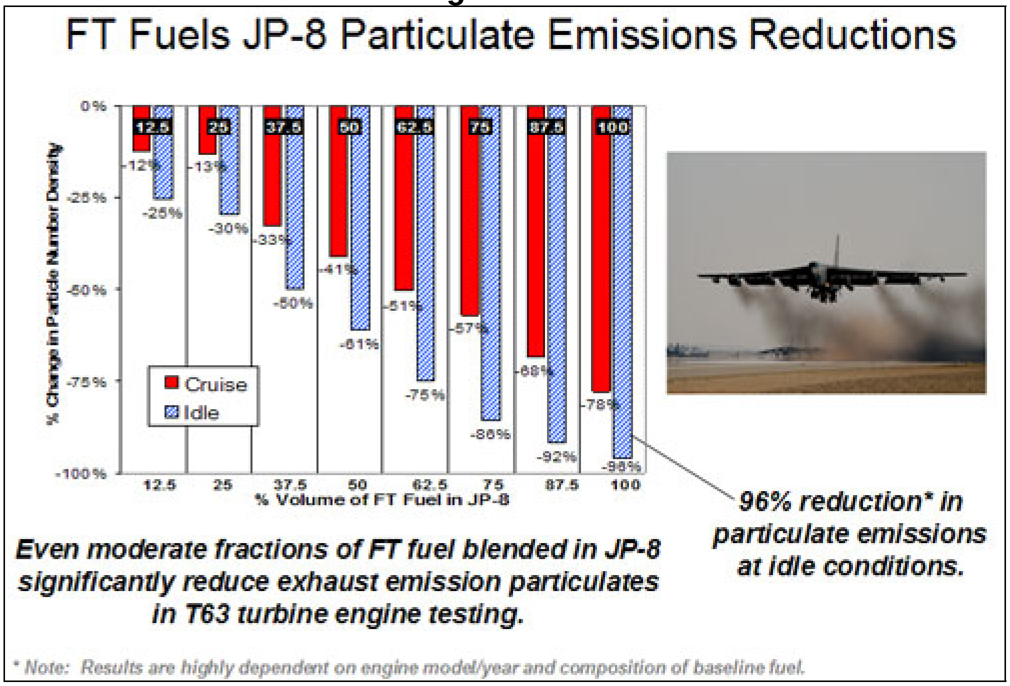
Source: Rentech, Inc.

Figure VII-2



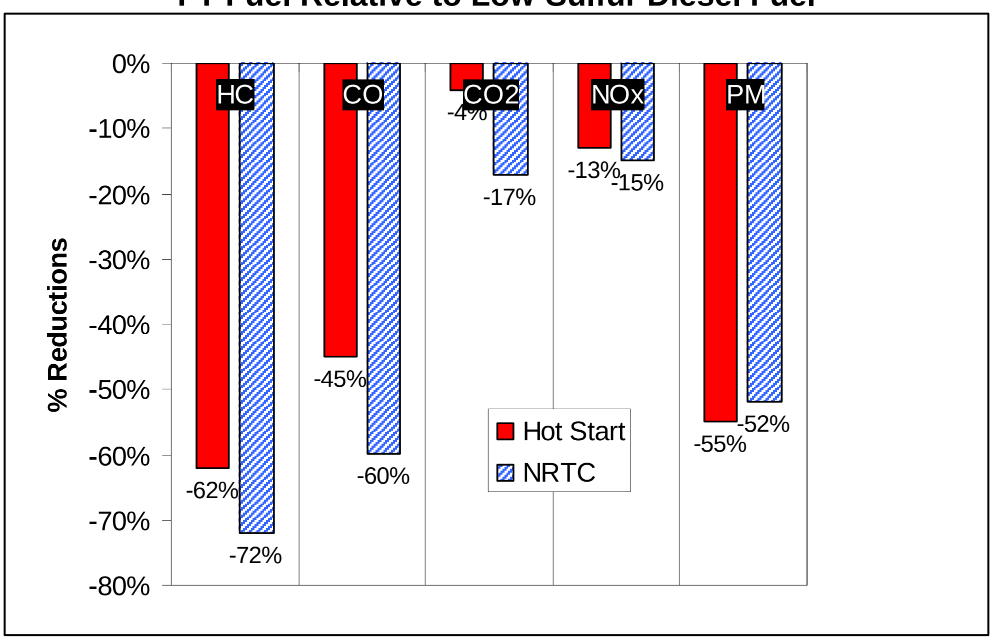
Source: Rentech, Inc.

Figure VII-3



Source: Rentech, Inc. Website and U.S. Department of Defense

Figure VII-4
Reduced Exhaust Emissions with
FT Fuel Relative to Low-Sulfur Diesel Fuel



Note: NRTC = Non-Road Transient Composite

Source: PowerPoint from U.S. Department of Defense, OSD, Advanced Systems and Concepts entitled “OSD Clean Fuel Initiative,” by Dr. Theodore K. Barna, Assistant Deputy Under Secretary of Defense, J. Edward Sheridan, and William E. Harrison III.

In addition, this same process enables the carbon dioxide contained in the coal to be captured in a form that can be either used as a commercial product or stored in the earth rather than being emitted into the atmosphere. The environmental profile of a gasification plant from an air emissions and water usage perspective is about equivalent to that of a large natural gas fed combined cycle power plant with traditional evaporative cooling, if the CO_2 is commercially used or stored.

CO_2 is most easily captured when it does not have to be separated from the other typical products of combustion (N_2 and other impurities). Gasification technologies are believed to represent a next generation of solid-feedstock-based energy production systems. Gasification breaks down virtually any carbon-based feedstock into its basic constituents, and this enables the economic, high-efficiency separation of regulated pollutants and CO_2. The resulting CO_2 gas stream is 90 to 99 percent pure, and is often at high pressure, making it suitable for transport via pipeline for commercial application or to a storage reservoir. If desirable or necessary, compression to even higher pressures can be accomplished economically because the starting point is not atmospheric pressure.

One currently viable commercial application for this CO_2 stream that also provides the opportunity for underground sequestration is Enhanced Oil Recovery. As discussed in Chapters III and IV, EOR is a process by which CO_2 is injected under pressure into old oil fields, enabling the recovery of what would otherwise be stranded oil reserves. For every ton of CO_2 stored, up to 3 or 4 barrels of crude oil can be recovered. The CO_2 sent to the oil field is injected into the oil reservoir, forcing the oil to producing wells. Some of the CO_2 will bypass the oil, but will be captured and re-injected. At some point, all the wells are sealed to assure permanent containment.

Demand for CO_2 and Infrastructure Development Required to Support CO_2 Utilization and Storage

CO_2 availability is currently limited in the U.S. outside of the present CO_2-Enhanced Oil Recovery producing areas (MS, CO-NM-TX, WY-UT, ND), and this causes very high CO_2 prices during summer high-demand periods. Commercial CO_2 suppliers often are unable to meet the summertime demand. Major sources of natural CO_2 that supply EOR projects are found mostly from underground sources in Colorado, New Mexico, Wyoming, and Mississippi. The capturing of CO_2 from manufacturing processes for EOR is scattered, with major sources in North Dakota (coal gasification) and Oklahoma (fertilizer plants). Some CO_2, a by-product of the fermentation process, is also captured at ethanol plants.

Increasing the production of useable industrially produced CO_2 addresses those consumption demands. Present reserves of natural CO_2 are large, but are not adequate to support an all-out effort to produce the technically recoverable oil resources that are amenable to recovery by CO_2 EOR. In the U.S. southern region (Gulf Coast and nearby areas), the target for EOR is 6 to 20 billion barrels of oil, but the huge CO_2 EOR resource requirements present a significant challenge.[1]

Assuming that future CO_2 requirements will be at least as high as result from state-of-the-art CO_2 EOR processes, there will be a need for between 30 and 120 TCF of CO_2 for the southern region alone. With the Permian Basin region requiring a similar amount of CO_2, the southern region cannot expect to receive CO_2 supplies from the pipelines serving West Texas. The Jackson Dome natural CO_2 resource in Mississippi may be able to supply part of the CO_2 for the southern region, but additional pipelines will have to be developed. In fact, additional pipelines will be required no matter what CO_2 resources might be developed, in order to reach the oil reservoirs of the southern region. Other regions also have high EOR CO_2 requirements that will not be met by available natural CO_2 sources, including the Permian Basin, the mid-continent states (especially Oklahoma and northern Texas), Alaska, California, and the offshore Gulf of Mexico.

The logical sources for the additional CO_2 requirements are the industrial processes that create excess CO_2 in the regions where the oilfields are located. One source will be from processes that emit high-quality by-product CO_2, such as fertilizer and cement plants. These sources can be placed into production faster than other sources, but generally will not be able to meet the total CO_2 requirements for a given region. The larger CO_2 resources will likely come from other energy production or process plants such as coal gasification/liquefaction plants, "polygen" plants and electric powerplants. These plants provide an excellent opportunity to help meet the demand for CO_2 for EOR. There are also CO_2-capture opportunities from other processes such as pulp mills, where aging energy-recovery facilities will need to be replaced soon and, with proper incentives, could utilize a gasification-combined cycle process to produce a virtually pollution-free, CO_2-rich gas stream.

An aggressive effort to replace aging single-function energy equipment, such as that used for power generation, with more efficient, multiple-function equipment, e.g. combined heat and power, will be an effective way to reduce U.S. energy requirements and can also generate reduced emissions with high-purity CO_2 for use in CO_2-EOR and in CO_2-Enhanced Coal Bed Methane (ECBM) recovery. The challenge is in creating the investment incentives for encouraging the development and construction of new, efficient total energy systems.

[1]The range of estimates is the result of multiple sources using different recovery factors and/or including different plays within their resource bases. The low-end estimate is the average (rounded) of the Texas Bureau of Economic Geology (BEG) and Advanced Resources International (ARI) for the "Gulf Coast" basins. The high-end includes the east Texas basin and other reservoirs in the states of Louisiana, Mississippi, and Alabama, drawing from BEG and ARI.

Incentives for Carbon Capture and Storage

Development of carbon capture and storage can be encouraged through incentives that could be in the form of higher prices for products and tax incentives for carbon capture and storage (CCS) technologies. For example:

- Investment tax credits and expensing rather than depreciation can help companies which initiate CO_2 EOR projects by reducing the impact of prerequisite large investments and CO_2 purchase costs incurred many months before incremental oil production can be expected. Similar credits could be granted to innovative projects demonstrating higher thermal efficiencies, cleaner energy production, carbon sequestration, and combinations of these.
- Royalty and severance taxes concessions on federal leases could help offset major necessary investments (e.g., CO_2 pipelines and injection facilities). Similar incentives can be provided by states, and such concessions could benefit both industry and government by prolonging the life of producing reservoirs.
- An after-tax "volume credit" for incremental oil production has been proposed as a protection against oil price uncertainty. The volume credit could apply to qualifying EOR produced crude oil or methane.

Need for Supporting Industries

New IGCC power plants, polygen plants, CO_2 capture plants, and conversions will create additional demands for construction and manufacturing resources, as will new pipeline construction. The potential for developing new CO_2 supplies in regions close to target oilfields is very good because of the industrial intensities of those regions. Numerous power, chemical, and oil refining plants operate in close proximity to the oil-producing areas (e.g., the Gulf Coast). Even so, hundreds of miles of new pipelines will be required to distribute the commodity to all of the oil fields needing CO_2. Maximum utilization of existing pipelines converted to CO_2 service and use of existing right-of-ways will minimize the impact of the infrastructure expansion.

VII.B.2. Indirect Environmental Considerations

The indirect environmental impacts of utilizing coal can be addressed using mitigation measures that are currently in place. Environmental protocols associated with the energy development activities will need to be adequately established to address the concerns of local communities and energy companies alike for the program to advance on the scale needed. Permitting processes will need to be standardized to the extent possible and streamlined to the maximum, while simultaneously allowing adequate public scrutiny and input.

Additional mining needed to produce the raw materials for future U.S. energy needs will require a robust program of environmental vigilance and mitigation. A combination of environmental regulations and modern mining techniques can preserve and restore the environment through such measures as limiting the amount of soil and rock removal, selective isolation of mine waste materials to prevent chemical leaching due to exposure to air or water, down-dip mining to prevent mineral-laden water from exiting the mining operation, and chemical treatment, as necessary, of water leaving a mine site to restore it to an acceptable quality. Upon abandonment, mines are typically sealed and monitored to prevent subsequent pollution problems.

In cases where a mining activity has resulted in longer-term water pollution, modern techniques can be applied to treat the mine effluent and thus mitigate the situation. An example of this is the case of an older West Virginia mining area where acid mine drainage had entered the watershed and caused the local stream (Deckers Creek) to become highly acidic. With mine operators adhering closely to new regulations and post-mine treatment of selected parts of the stream, the creek's water chemistry has significantly improved and continues to improve. In a 25-year study, the water pH increased by 1 to 2 units (current pH = 5.4 to 6.5 versus 3.7 to 5.2 at the beginning of the study). Acidity has declined by more than 50% at all sampling points along the stream.

In addition to improvements in mining techniques, responsible restoration strategies such as reforestation can greatly enhance the value of the land after mining is completed, and will help mitigate possible negative effects of the operation. A combination of grade control, ground cover, and reforestation will limit the rates of water drainage from the mine site and can be designed to uptake and sequester undesirable chemical elements and CO_2. When used in parallel with mining operations, reforestation activities can be utilized as part of fugitive emission and run-off control.

Increases in coal and oil shale mining can be accomplished responsibly. Contrary to common belief, existing mining laws are very stringent and strictly prohibit pollution. In addition, remining of previously abandoned mined areas and mine reforestation programs are having positive environmental results. We encourage mining regulatory authorities and mining companies to advance remining and reforestation programs. Experimental reforestation projects have demonstrated that tree growth rates can be dramatically increased from normal rates experienced in nature by preparing mined ground properly before planting. Young, fast growing trees capture greater volumes of CO_2. The new soil preparation techniques provide greater moisture collection for the trees, and reduce water runoff from mine sites. Expanding programs that incorporate accelerated tree growth into mine reclamation plans has great promise for reestablishing forests, increasing property values of mined land, providing a dynamic new source of arbor fuel crops and wood products resources, and capturing CO_2. Reforestation is a natural form of CO_2 capture and storage.

Research by the Virginia Polytechnic Institute and State University and the University of Kentucky has confirmed that highly productive forest land can be created on reclaimed mine land by using a Forestry Reclamation Approach, and the Office of Surface Mining has determined that this technology can be implemented under current federal regulations. The Forestry Reclamation Approach has five fundamental parts:

- Create a new soil medium by replacing the original soil with four feet of surface soil, weathered sandstone, or the best available material.
- Loosely grade the topsoil or topsoil substitutes to create a non-compacted soil growth medium.
- Use native and noncompetitive ground covers that are compatible with growing trees.
- Plant two types of trees - early succession species for wildlife and mine soil improvement and commercially valuable crop trees.
- Use proper tree planting techniques.

Reforestation creates economic value through the carbon-storing capabilities of trees. Reclaimed forests naturally capture and store a great deal of CO_2, which is a fertilizer for forests. Figure VII-5 illustrates that extensive vegetation growth is storing significant amounts of carbon on a 200-acre Eastern Kentucky reclaimed coal mine.

Biomass carbon sequestration refers to the transformation of atmospheric carbon dioxide into solid carbonaceous components, such as those comprising trees, shrubs, other vegetation, and soil organic matter. This biomass can in turn be gasified to produce liquid fuels. Once the carbon dioxide has been transferred into these materials, it is effectively stored (i.e., sequestered) until decomposition occurs. Even after trees are harvested, some of the carbon remains trapped in solid form if the trees are converted into wood products such as lumber, plywood, and other building materials.

VII.C. Environmental Keys to Successfully implementing the AES Energy Security Initiative

The key to the successful implementation of the American Energy Security Initiative is the cooperation and dedication of all its stakeholders. Energy companies, regulatory authorities, and the community at large must participate fully and earnestly to understand what is at stake in terms, not only of energy security, but also in the protection and responsible development of all life-essential resources. A continuing dialog will be needed to achieve the levels of efficiency in mine development and environmental preservation for this energy initiative. Mine permitting and development must proceed rapidly, but responsibly, to accomplish the goal.

Figure VII-5
Example of Vegetation Growth on a Reclaimed Eastern Kentucky Coal Mine

Source: Chuck Meyers, Office of Surface Mining.

Because the new alternative liquid fuels production plants are so clean, they provide another, somewhat indirect benefit – fewer refineries than would otherwise be needed will be built or expanded. Although new refineries will be needed and they will also be cleaner than their older siblings, they will not be as clean nor will they be able to produce fuels that burn as cleanly as those from the polygen plants. Low to no-sulfur fuels from the polygen plants will decrease transportation emissions significantly compared to fuels refined from crude oils.

As the technologies progress for polygen plants, other benefits will become more evident. According to USDOE studies, IGCC power plants can be expected to use 40 percent less water than conventional pulverized-coal power plants (360 to 540 gallons per megawatt-hour (MWh) versus 600 to 660 gallons per MWh. Adding advanced pollution controls and CO_2 scrubbers to pulverized-coal plants could increase the water usage to more than 1,000 gallons/MWh.

If biomass fuel crops are used together with coal supply to feed future polygen plants, atmospheric CO_2 can actually be decreased while creating liquid fuels and chemicals because these plants produce oxygen while recycling CO_2 naturally. Eventually, the polygen plants may operate primarily to produce hydrogen, the ultimate, all-purpose clean fuel that produces only water as a byproduct of consumption. These plants thus have the potential to accelerate the transition to the hydrogen-based economy of the future.

Managing the Challenges

The ultimate net effect of the American Energy Security initiatives will be a transformation of the energy sector into one that is very efficient, highly-competitive, responsive to security threats, and environmentally responsible. Managing the challenges of the AES program will not be easy and will require a substantial commitment to resolve various issues and problems. Development of new polygen plants and supporting infrastructure will require more incentives than high oil prices. Prior bad experience with oil-price volatility has dealt a severe blow to the domestic oil industry, making energy companies reluctant to invest heavily in the U.S. where the return on investment is often too low to meet the risk-based minimum.

VII.D. Benefits

VII.D.1. Clean Energy and Energy Independence

As discussed in Chapter V, energy utilization and economic growth are highly correlated. The U.S. has been able to limit its energy dependence over recent decades with technological improvements that permit production of more goods and services at a lower energy intensity, i.e., using less energy per unit of production. Nevertheless, U.S. energy consumption continues to rise and oil import dependency is particularly critical with regard to liquid fuels for transportation. The U.S. is very dependent on liquid fuels for almost all transportation needs, including the deployment and the activities of military units. Both U.S. security and economic well-being depend on having secure supplies of transportation fuels, which will be comprised almost entirely of liquid fuels for the foreseeable future.

Liquid fuels are derived mostly from crude oil because, historically, oil has been readily available at low prices, making it the lowest-cost option for producing liquid fuels. However, with the price of crude oil fluctuating between $65 and $75 per barrel, liquid fuels from other sources have become economically viable. When one considers the instability of the oil-rich Middle East and deteriorating U.S. relationships with some countries in that region, a case can be made for developing alternative fuels from secure sources, even if oil prices fall below the threshold for alternative fuel profitability. The U.S. should not allow itself to get into a position where an extended interruption of oil supplies would cripple its economy and reduce national defense capabilities. A secure supply of liquid fuels can be developed at reasonable cost, possibly at a fully economic cost.

The United States, which has always been on the cutting edge of technological development, can remain in the forefront in development of the technologies for clean, alternative fuels. New and improved technologies will likely result from the intense development of low-carbon or carbon-free liquids plants that employ carbon capture and storage (CCS), and these technological improvements will provide marketable commodities on the world market. In addition to developing improved, clean technologies for producing alternative fuels, the U.S. will continue to improve CO_2 EOR technologies, an area where it is already the world leader. CO_2 EOR will be used increasingly around the world, and the U.S. will be in a position to capitalize on its expertise. CO_2 injection can also be used to enhance the production of coalbed methane and natural gas, and this value added from CO_2 use converts the gas from a liability to a strategic asset.

The development of a robust alternative fuels industry that is competitive and which relies on plentiful resources outside the Middle East will serve to constrain the volatility of crude oil prices. As previous attempts by OPEC to control the world oil market were deterred by oil development in the North Sea and other oil provinces, an alternative fuels industry likewise will prevent OPEC and future cartels from doing so. Not only will this help provide energy security for the U.S., but the resulting stabilized oil prices will also encourage and assist third-world development.

VII.D.2. Clean Air and Water

Modern alternative fuels processes have evolved to the point where they are environmentally clean and lend themselves to the capture of undesirable residuals such as SO_2, NO_x, CO_2, and mercury. Virtually all emissions can be reduced by the implementation of an aggressive, well-planned development of alternative fuels. The various energy utilization and conversion technologies that have been developed in recent years employ the best techniques for eliminating pollutants and for making the capture of CO_2 much easier.

There has thus far been little incentive for industry to replace older equipment with new cleaner and more efficient process equipment, whether it be a refinery or power plant. In fact, there has been a clear financial disincentive: It has been cheaper and more economic to repair and refit old equipment than to replace it with new equipment. The laws legislating clean air and water required such large reductions in pollutants that it is often much less costly to repair and maintain old equipment and machinery than to replace it, thus defeating much of the purpose of the laws. In essence, the “stick without a carrot” approach has not worked that well.

To get things moving toward stable and secure energy for the country, we need to take a fresh look at the basic objectives of the environmental quality rules and regulations and add a meaningful carrot to inspire. With a carrot (aka, real incentives), an alternative fuels development effort can be a win-win-win proposition. Older, less efficient plants can be significantly improved or replaced to obtain cleaner air and better energy efficiency; new, clean and efficient polygen plants can be built to provide the cleanest burning fuels possible while simultaneously capturing and storing CO_2; and additional CO_2 EOR production could be brought on line – production that could not be realized for many years, if ever, relying solely on natural sources of CO_2.

VII.D.3. Improved and Streamlined Procedures for Energy Development

One of the outcomes that will result from a coordinated liquid fuels program will be a set of highly effective energy development and environmental protection processes. There are many opportunities for improving environmental quality with the development of new plants and new fuels to supplement and/or replace U.S. imports of oil-based fuels. The undertaking of such a massive effort represents an opportunity to reshape U.S. environmental protection laws to achieve their intended objectives (clean air and water) while making energy development permitting processes both faster and more effective in terms of environmental protection.

Energy companies and regulatory bodies at local, state and federal levels have shown that they can work together to develop reasonable approaches to meeting environmental requirements. Additional efforts focused on some of the more specific problems are required to help the U.S. achieve energy security and independence.

There are numerous benefits that will be derived from the American Energy Security program, as have been realized from other major technology development programs, such as the space program. The time has arrived for technologies like coal-to-liquids and biomass conversion. The learning curves can and should be compressed and the technologies developed at a much faster rate than "business as usual." Not only will the AES program reduce U.S. dependence on foreign energy supplies, it will stimulate many areas of the economy, encourage new technology export opportunities, and create large numbers of well-paying jobs for decades to come. Early failures and successes will lead to improved processes, better equipment, and better practices for more efficient energy production and a cleaner environment.

VIII. POLICY RECOMMENDATIONS AND IMPLCATIONS

VIII.A. Government's Role in Risk Mitigation

The initial expenditures required to jump-start a new domestic alternative liquid fuels manufacturing industry will require significant investment of private capital. The risks associated with such an undertaking are perceived to be substantial, given the historic volatility of oil prices and, more recently, those of natural gas. The most significant contribution the Federal and state governments can make is to lower the risk profile of investment.[1] This will mitigate risk and project sponsors, backed by large pools of private capital, will have the incentive to build alternative liquid fuels plants.

The Southern States Energy Board recommends that the risk mitigation and capital funding policies summarized below be implemented to encourage the private sector to step forward on a massive scale. The specific fiscal, tax, legislative, and regulatory recommendations presented below are designed to encourage private sector commitments to seize this opportunity and provide for U.S. energy security and independence.

VIII.B. Summary of Federal Fiscal, Tax, Legislative, and Regulatory Recommendations

Issues and policy options related to the prioritization and catalyzing of a new domestic alternative liquid fuels industry are extremely complex and important. The policy recommendations summarized below are believed to be key to the success of a comprehensive national initiative for an alternative fuels harvesting and manufacturing initiative. The policies recommended include:

1. Extension of the $0.50 per gallon alternative liquid fuels excise tax credit
2. Provision of accelerated cost recovery to alternative fuel plant owners for refining alternative liquid fuels
3. Incentivizing the refining of alternative liquid fuels
4. Provision of explicit DOE authority and appropriations for loan guarantees
5. Funding the Department of Defense alternative fuels testing and development program
6. Authorization and funding military purchases of alternative fuels under long-term contract

[1]Government risk mitigation policies were successful in developing the Canadian oil sands industry, which currently produces more than 1 million bpd of liquid fuels and resulted in Canada being ranked as the nation with the third highest oil reserves in the world. Further, as discussed in Section IV.B.1, risk mitigation policies were critical in the development of Sasol, which currently produces 160,000 bpd of substitute liquid fuels and is one of the largest and most technologically advanced energy companies in the world.

7. Elimination of the $10 million cap for tax exempt industrial development bonds
8. Provision of regulatory streamlining for the production of alternative liquid fuels
9. Establishment of a self-sustaining government corporation to provide market risk insurance
10. Expansion of the strategic petroleum reserve program to include alternative liquid fuels products
11. Provision of incentives for existing ethanol plants to convert to coal as a fuel source
12. Provision of incentives for enhanced oil recovery and enhanced coalbed methane recovery using CO_2 captured from alternative fuel plants

These recommendations are summarized below.

1. Extend the $0.50 Per Gallon Alternative Liquid Fuels Excise Tax Credit

The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users, SAFETEA-LU 2005 extension, provides a $0.50 per gallon excise tax credit for certain alternative liquid fuels, including coal-to-liquids products. This incentive is set to expire in 2009, before any major new coal-to-liquids and oil shale plants (for example) can come online. Its extension through 2020 and the inclusion of oil shale products will provide critically needed market incentives for the development of alternative liquid fuel plants.

2. Provide Accelerated Cost Recovery to Alternative Fuel Plant Owners

Authorization for 100 percent expensing in the year of outlay for any alternative liquid fuel plant begun by 2020 will provide a substantial tax incentive to build alternative fuels manufacturing capacity, with the government recapturing the deferred taxes in the early years of a plant's operation.

3. Incentivize the Refining of Alternative Liquid Fuels

We recommend extension of the now temporary expensing allowance for equipment used in refining to 100 percent of any required additions to existing refineries needed to handle domestic alternative liquid fuels products (see EPAct 2005, § 1323). This incentive will redirect refinery owners to domestic feedstocks and away from imported feedstock sources.

4. Provide Explicit DOE Authority and Appropriations for Loan Guarantees

The Energy Policy Act of 2005 establishes a loan guarantee program within DOE. However, the DOE view is that the Federal Credit Reform Act of 1990 contains a requirement preventing DOE from issuing any loan guarantees until they have an authorization, including a loan volume limitation, in an appropriations bill. It is recommended that Congress provide explicit authorization in the form of a federal loan facility to support the first approximately 100,000 barrels per day of new commercial production capacity for coal-to-liquids, biomass-to-liquids, and oil shale-to-liquids facilities. It is also recommended that appropriations be provided for technologies demonstration, as provided in the Energy Policy Act of 2005.

5. Fund the DOD Alternative Fuels Testing and Development Program

The Department of Defense currently has a program underway to evaluate, demonstrate, and certify turbine fuels from alternative energy resources for use in tactical vehicles, aircraft, and ships. Fuel sources include Fischer-Tropsch fuels made from domestic coal, refined fuels derived from oil shale kerogen, and renewable/bio-based fuels, and the ultimate goal is to develop a single Battlefield Use Fuel of the Future (BUFF). At the center of this development effort is a DOD fuel testing program, and we encourage Congress to fully fund this critical program through FY 2013. The military need is approximately $500 million over a 5-6 year period, beginning in 2007.

6. Authorize and Fund Military Purchases of Alternative Fuels Under Long-term Contract

Total oil consumption by U.S. military forces is approximately 300,000 bpd. Through the development of BUFF specifications, it is believed that a substantial portion of this requirement can be met with domestically produced alternative liquid fuels. DOD desires to enter into long term contracts for the purchase of alternative fuels made in the U.S. from domestic resources. This is part of DOD's Total Energy Development (TED) Program, the stated mission of which is to "catalyze industry development and investment in [alternative] energy resources." Congressional support is encouraged for DOD's TED program, including extending its long-term contracting capabilities from five years to as long as 25 years. It is recommended that appropriations and necessary authorizations and funding for these programs be given high priority.[1]

7. Eliminate The $10 Million Cap for Tax Exempt Industrial Development Bonds

To encourage investment, certain pollution control and solid waste disposal facilities are currently not included in the $10 million limit on tax exempt Industrial Development Bonds (IDBs). It is recommended that alternative liquid fuels production facilities be added to this list of activities having no tax exempt IDB size limits. This will lower the cost of capital to build new alternative liquid fuels projects and to expand existing ethanol and biodiesel plants.

[1]DOD fuels purchases under long-term contract can help establish a foundation on which to build a new alternative fuels industry, and can secure the high quality U.S. made alternative liquid fuels desired by DOD.

8. Provide Regulatory Streamlining for the Production of Alternative Liquid Fuels

In order to facilitate the rapid scale-up of alternative liquid fuels production capabilities in the U.S., regulatory changes are necessary. Standardizing, simplifying, and expediting the permitting process for manufacturing/processing facilities, mines, agricultural operations, and necessary infrastructure is crucial. The "not in my back yard" mentality, often accompanied by costly time consuming litigation and obstructionism, needs to be countered with legislation and leadership. Our recommendations to address this problem include:

- Standardize, simplify, and expedite permitting and siting with joint federal, state and local processes, policies, and initiatives.
- Make appropriate federal, state and local government sites available for alternative liquid fuels manufacture, including Base Realignment and Closure (BRAC) military sites.
- Exempt initial alternative liquid fuels processing facilities from New Source Review (NSR) and National Ambient Air Quality Standards (NAAQS) offset requirements.
- Encourage local leadership to modify approaches to zoning and other land use and business regulations to accommodate the strategically important new activities of alternative energy harvest and manufacture.
- Prioritize, expand, and promote the reforestation work being done to dramatically accelerate the rate of tree growth by creating optimal soil conditions at reclaimed mine sites.

9. Establish a Self-sustaining Government Corporation to Provide Market Risk Insurance

Congress is encouraged to establish the Strategic Energy Security Corporation (SESC) as a self-funding, self-sustaining government corporation that will administer a new alternative liquid fuels market insurance program to protect against predatory pricing by OPEC and others. SESC will provide the following functions:

- Collect insurance premiums from companies that "opt in" to the SESC insurance program
- Invest net premiums (after administrative costs) in an insurance fund for future payout to program members if and when necessary
- Facilitate market insurance payments to members if oil prices fall below a defined "Low Trigger Price"
- Administer the collection of "standby" insurance fees, to be levied on imported oil if oil prices fall below the "Low Target Price" and the accumulated investment pool of insurance premiums (including investment returns thereon) is exhausted

This proposal introduces the concept and structure of a new, self-sustaining U.S. Government corporation created to offer “fuel neutral” market risk “insurance” to owners of U.S. alternative liquid fuels plants. The primary function of the SESC program will be to insure viable market prices for qualifying alternative liquid fuel plants in the event oil prices fall below a designated “Low Trigger Price.” This will be accomplished by providing insurance payments to insured plant owners if any oil products from their plants sell at prevailing market prices that are less than the Low Trigger Price on a crude oil equivalent basis.[1]

10. Expand the Strategic Petroleum Reserve (SPR) Program to Include Alternative Liquid Fuels Products

Stockpiling crude oil in a centralized location has its limitations, since crude oil needs to be refined to be useful. The logistics of moving SPR crude to refineries having available capacity and then transporting the refined products to locations in need is cumbersome and takes time (time being of the essence in a crisis). There are only four centrally located SPR storage sites in the U.S. -- two in Texas and two in Louisiana. All four sites are centrally situated on the hurricane-prone Gulf Coast, making them vulnerable to natural disaster and also to enemy attack.

Congress should examine the feasibility of purchasing and storing “finished” alternative fuel products such as diesel fuel, jet fuel, heating oil, and ethanol at a number of locations strategically dispersed throughout the U.S., as an extension of the SPR program. Fischer-Tropsch (FT) wax produced from coal, biomass, and oil shale may be an ideal product for this purpose. The FT process is capable of making a biodegradable wax as an alternative to producing diesel and jet fuels. This wax has a very long shelf life, and can be upgraded to superior quality fuels much more quickly and inexpensively than crude oil. In general, a variety of alternative fuels could be purchased by the SPR under long-term contract to control costs and to help establish a vibrant, rapidly expanding alternative fuels industry. Congress should authorize the sale of portions of the crude oil currently in storage on the open market to fund available alternative fuels purchases.

11. Provide Incentives for Existing Ethanol Plants to Convert to Coal

Until very recently, the ethanol plant fuel source of choice for process heat and electricity was natural gas. However, with the recent increases in natural gas prices, new ethanol plants are opting for coal firing. Like crude oil, limited domestic natural gas supplies have necessitated increasing imports of this fuel as LNG to produce ethanol. To promote energy efficiency and lower energy imports, we recommend providing for 100 percent expensing in the year of outlay for the cost of converting ethanol plants currently using natural gas to domestic coal, if the new plant is placed in service by 2010.

---

[1]More details on the SESC initiative are provided in Appendix A and in an American Energy Security Study concept paper, available on the SSEB website at www.SSEB.org.

12. Provide Incentives for Enhanced Oil Recovery and Enhanced Coalbed Methane Recovery Using CO_2 Captured From Alternative Fuel Plants

The capture and use of the CO_2 from alternative liquid fuel plants can greatly expand domestic oil production from existing oil fields and enhance methane recovery from coalbed methane operations. To lower the barriers to expanded use of CO_2 injection we recommend:

- Exclusion of the oil produced from the Alternative Minimum Tax (AMT)
- Increasing the investment tax credit to 50 percent
- Provision of Federal royalty and severance relief until the investment in CO_2 injection is recovered
- Provision of state royalty and severance tax relief until the investment in CO_2 injection is recovered
- Provision of access to Federal and state lands for construction of CO_2 pipelines

VIII.C. The Critical State and Local Role: Incentives and Coordinated Permitting for Alternate Transportation Fuel Facilities

Development of a domestic alternative transportation fuels industry as envisioned by the American Energy Security study will require cooperation between federal, state and local governments and private industry. State incentives play a critical role, which can jump-start early facilities, complement federal incentives, and incentivize early private sector commitments.

States can accelerate plant deployment by providing a variety of incentives during the development phase to facilitate site selection and permitting and to achieve the financial close of projects. The extent and nature of state support during this phase can have a beneficial impact on bringing equity investors to a project and attracting private debt financing. Tax abatement reduces the financial performance risk, tax credits promote equity investment by private industry, and loans assist with debt financing. Matching grants or loans to assist with development studies can accelerate development of projects. Since most permitting is at the State level, the permitting system can reduce financial risk and facilitate development by offering coordinated permitting and a transparent timeline with clear regulatory requirements.

It should be noted that alternative liquid fuel facilities based on gasification of coal, biomass, oil shale derivatives, and petroleum coke will generate multiple products, including electric power for the plant's own use, with some exportable to the grid. The generation of power based on gasification makes these facilities eligible for many state programs that provide support for generation of power from clean technologies. State "green" and "renewables" programs are also platforms to build on. Providing "green" qualification to plants that facilitate CO_2 capture and sequestration, and "renewable" status to those that use biomass as a portion of feedstocks, should be considered.

The SSEB strongly encourages states to adopt a portfolio of programs and initiatives that support the diverse alternative liquid transportation fuels sources featured in the American Energy Security study.

Recommendations

1. Authorize and fund multi-year State and local government purchases of plant output, including alternative transportation fuels under long-term contracts.
    a. Arrange for transportation fuel and electricity purchasing under multi-year contracts of at least 10 years.
    b. Arrange for state and local contractors to purchase fuel.
    c. Secure transportation fuels under multi-year contracts for first responders for use in case of emergencies.

    Comment: Most facilities will be project financed and will require long-term off-take agreements for the plant output, especially the transportation fuels produced. The states are in a unique position to offer long-term contracts to support state transportation fuel and electricity needs, and this alone could significantly facilitate facility financing. For its part, through long-term contracts the state is assured of a stable, affordable fuel supply not subject to the price volatility of petroleum products or supply disruptions caused by natural disasters. Moreover, fuel made through the Fischer-Tropsch process has a long shelf-life of at least 8 years (unlike petroleum diesel which must be used within 4-6 months), making it suitable for first responders. West Virginia has announced its willingness to enter long-term agreements, and Pennsylvania has instituted such a program.

2. Provide State loans and/or grants on a matching basis with private industry to assist with preliminary engineering and site qualification.

    Comment: The highest risk in any project is early stage development. States can jump-start the first projects by assisting in site selection using their resource bases and by providing development funding on a matching basis. For example, Illinois provides a 50/50 match with private industry to support market-driven clean coal projects, and Mississippi has authorized $15 million in bond funding to make the Natchez site for the Rentech proposed plant "development ready."

3. Provide for tax incentives including:
    a. Investment tax credits,
    b. Corporate tax abatement, and
    c. Property tax abatement

    Comment: Tax credits assist in bringing private equity investment into projects. Many state economic development programs offer credits and tax abatement for projects, that promote economic growth and create jobs. As noted above, transportation fuel projects produce large numbers of high-paying plant jobs and significant construction employment. Mississippi has an extensive tax incentive program, and Ohio and Pennsylvania provide other relevant examples.

4. Provide Fiscal Incentives, including:
   a. Loans at favorable rates, and
   b. Qualification for industrial development bonds.

   Comment: Government loans and bonds reduce the debt financing risk through lower interest rates, flexible payment terms, and an added source of debt financing. This can attract private debt financing. Many states offer industrial development bonds for economic development projects; for example, Ohio has extensive bonding authority through the Ohio Air Quality Development Authority.

5. Incentivize the use of CO_2 for carbon capture and storage:
   a. Provision of state royalty and severance tax relief until the investment in CO_2 injection is recovered.
   b. Provision of access to state lands for construction of CO_2 pipelines.

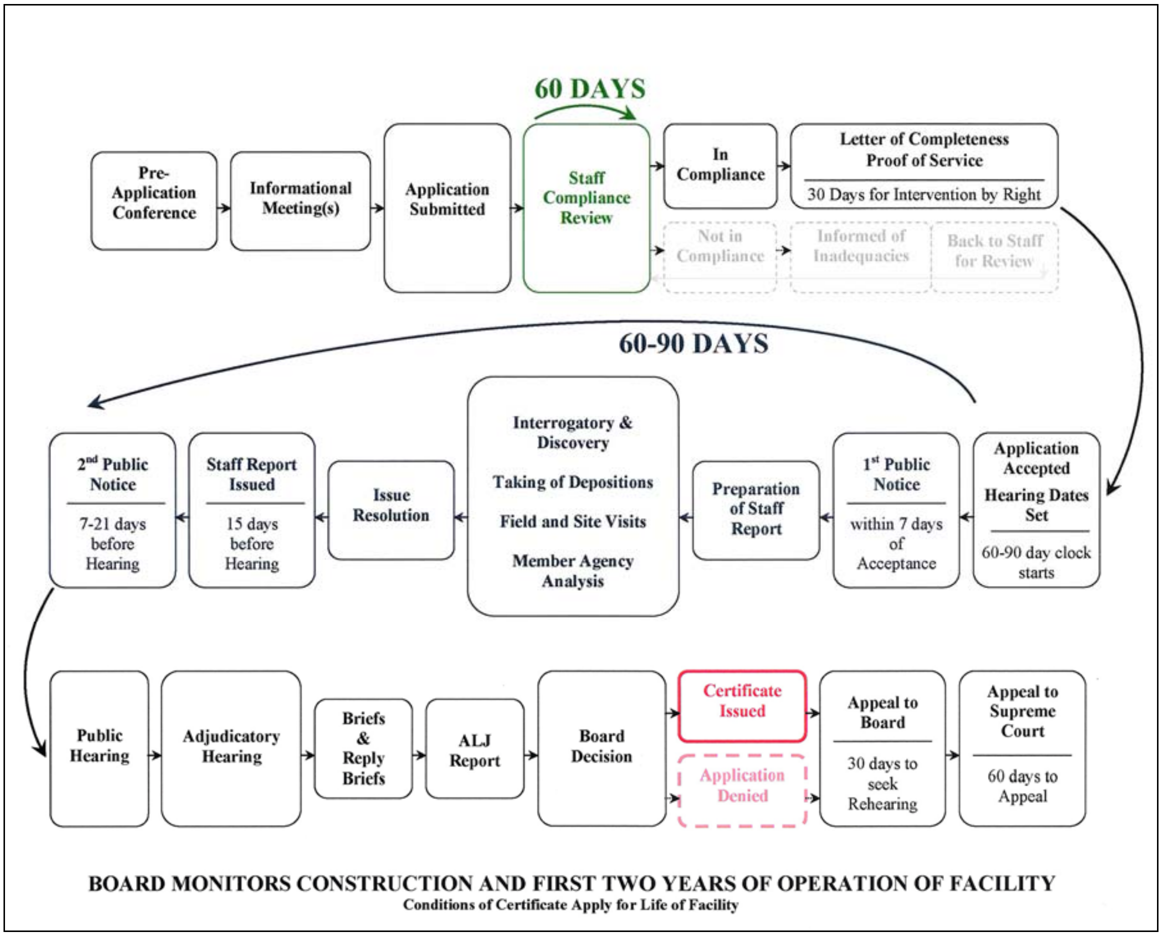
   Comment: Incentives to stimulate interest in using the produced CO_2 for enhanced recovery of oil, coalbed methane and natural gas, and for other productive purposes, can provide important financial stability (additional revenue streams) for plant developers. It will also add impetus to these environmentally compelling activities. The injection of CO_2 requires additional investment beyond the normal infrastructure. New pipelines need to be built to connect the plant to injection areas and extensions or modification of existing pipelines are also required. Louisiana and Oklahoma abate taxation until the incremental investment is recovered, and Arkansas, Florida and Texas provide reduced severance tax rates for CO_2 enhanced recovery.

6. Provide regulatory streamlining and central state agency coordination of the permitting process for the production of alternative transportation fuels, including:
   a. Pre-qualification of sites.
   b. Identification of options to meet air and water requirements.
   c. Standardize and expedite permitting and siting under established timelines with joint federal, state and local processes, policies and initiatives.
   d. Make appropriate state and local government sites available for alternative transportation fuels manufacture, and
   e. Encourage local authorities to modify approaches to zoning and other land use and business regulations to accommodate alternative transportation fuels production facilities.

Comment: The timing, coordination, transparency and clarity of a state's permitting can significantly affect the development of a project and the time required to achieve financial close. This is because all state permits must be issued before a project can close on the financing needed to build the project and construction can begin.

The SSEB believes that Ohio's siting program is an excellent model for a state permit system. Established in 1972, it has served as a model for many other states. All permits for a plant generating at least 50 MW of power are processed through the Ohio Power Siting Board with a well-defined and coordinated process that includes public participation and input by all stakeholder permitting agencies and local governments. The flow chart of the Ohio model is given in Figure VIII-1.

Figure VIII-1
Ohio Power Siting Statute Process Flowchart



7. Involvement of Research and Development enterprises:

   Comment: The involvement of state universities in research and development of alternative liquid fuels and transportation technologies is important to the success of the federal and state programs.

Discussion of Some SSEB State Activities

<u>Kentucky</u>

There are a number of incentive programs in place that could be used to advance anticipated CTL technology development projects. For example:

- Legislation (HB 299), sponsored by Representative R. Adkins together with 60 co-sponsors was introduced in the Kentucky House on January 10, 2006 and passed onto the Senate on January 26 "Concerning the Need For National Energy Independence and the Opportunity to be Found in Coal-To-Liquid Conversion and Bio-Based Alternative Fuels."
- HB 299 also "directs the Office of Energy Policy to develop a strategy for production of transportation fuels from fossil energy resources and biomass."

OEP staff indicated that part of the strategy will be the creation of incentive programs targeted directly at CTL projects.

<u>West Virginia</u>

To support the CTL initiative, the Governor Manchin is:

- Using the re-established West Virginia Public Energy Authority to create the implementation plan
- Directing the West Virginia Development Office to assist with identification of potential site locations, infrastructure requirements, siting, permitting, and construction of facilities
- Directing the West Virginia Department of Environmental Protection to work with the Public Energy Authority and potential investors to facilitate permitting and construction
- Requesting the West Virginia PSC to facilitate certification of any necessary utility infrastructure and to work with FERC and transmission operators to facilitate interconnection to the grid

In addition, it is anticipated that the state's colleges, universities, and technical schools will play an integral role, training workers for the mining, transportation, construction and operations jobs that will be created.

However, the discussions recently begun in West Virginia between the state government and the coal industries regarding CTL initiatives were temporarily suspended because of recent mine accidents. The state currently has programs to provide:

- Technical support to coal companies
- Assistance in the development of strategic partnerships
- Assistance in locating appropriate sites for new facilities, e.g., with access to such resources as water, electric power, roads, etc.
- Assistance in locating and securing needed capital for new ventures.

In addition, as part of the state's effort to more aggressively become involved in overcoming safety problems in the mines, the governor has reconstituted the Public Energy Authority, which may also be used to help establish CTL facilities. As yet, however, there has been no formal action to encourage the industry to initiate serious efforts into the CTL technologies.

The state's Coal Field Development Division's Industries of the Future Group is initiating evaluation of incentive programs that may be directly applicable to CTL programs.

Discussion of Other State Activities

<u>Pennsylvania</u>

State government incentives and support include:

-- A consortium, including the State of Pennsylvania, to purchase plant output
-- Existing incentives: Tax credits, financing assistance, grants, job training, etc.
-- Alternative Energy Tax Incentive Act
-- Alternative Fuels Incentive Grant Program
-- Energy Deployment for a Growing Economy
-- Alternative Energy Portfolio Standard

At present, incentive programs specifically targeted at CTL technology do not exist in Pennsylvania. However, the state does have in-place active incentive programs that would apply to CTL as well as other technologies. These programs include the Opportunity Grants Program, Job Training Assistance programs, Job Creation Tax Credits, Economic Stimulus Plan, Tax Increment Financing Guarantee Program, Research and Development Tax Credits, etc.

A bill, the Alternative Energy Tax Incentive Act (HB 634), has recently been introduced in the Legislature which specifically cites "coal derived liquid fuels" along with other alternative fuels, gas, and liquids. The Alternative Fuels Incentive Grant Program, was created in 1992 and expanded in 2004 and, although its emphasis is on vehicles, it appears to be eligible to developers of “coal-derived liquid fuels.”

Pennsylvania is actively assisting the WMPI CTL project by:

- Awarding WMPI $47 million in investment tax credits.
- Providing $465 million in loan guarantees
- Providing exemption from all state and local taxes through 2013
- Facilitating an agreement where the state and its trucking association will purchase nearly all of the project’s product

The governor is also proposing programs to support the Energy Deployment for a Growing Economy (EDGE) initiative which would support alternative liquid transportation fuel projects through such incentives as:

- Priority funding programs through the state’s Economic Development Financing and Energy Development Authorities
- Permitting long-term project-owner/customer contracts to attract investors
- Allowing synthetic gas producers to provide services and product to limited industrial users without the need for adherence to utility regulation
- Allowing utility owners of new plants to supply electricity under the pricing and cost-recovery structure specified in the Alternative Energy Portfolio Standard (Act 213).

There is also substantial federal government support for the WMPI project:

- It has received $7.8 million from the U.S. Department of Energy's Clean Coal Power Initiative for engineering studies
- It is expecting to receive $100 million from the U.S. Department of Energy's Clean Coal Power Initiative

Illinois

The Illinois Department of Commerce and Economic Opportunity and the OCD promote the in-state coal industry with various incentives, some of which are applicable to CTL development. These include:

- Funding R&D and demonstration of clean coal technologies
- Developing and promoting comprehensive energy and Illinois coal production policies and strategies
- Identifying new domestic and international uses and markets for Illinois coal and byproducts and helping coal producers penetrate those markets
- Conducting education and awareness campaigns

Most existing and proposed legislation dealing with incentives to the coal industry appears to be aimed primarily at extraction of coal. However, there are specific references to "coal demonstration and commercialization" and to "preparation, combustion, gasification, liquefaction or other synthetic process, environmental control, or transportation method" -- for example in the Illinois Compiled Statutes 730/2 Chapter 96½, paragraph 8202. It appears that most of the incentives legislation is applicable to CTL.

<u>Montana</u>

Highlights:

- Aggressive efforts by the governor
- Existing incentives: Tax increment financing, property tax relief, grants for job creation and for job training, alternative energy revolving loan accounts
- Legislature is proposing targeted CTL incentives

There are currently no incentive programs specifically targeted at development of CTL plants. However, there are existing financial incentive programs for new business development that may be applicable. These include:

- Tax increment financing that provides for municipalities to issue bonds to pay infrastructural costs incurred in connection with new construction
- Property tax relief programs which will allow a 50 percent reduction for the first five years
- Payments of $5,000 to a corporation for each additional new employee
- Payment of $5,000 to a corporation for training a new employee
- Alternative energy revolving loan accounts

Currently there are no guaranteed market incentives, but these will be considered during the 2007 legislative session. Discussions with the state Economic Development Officer indicated that the best incentive Montana has is the aggressiveness on the CTL issue of its governor.

The Director of the Montana Coal Council was not aware of any development projects underway or any incentive programs to encourage development. He also noted that the governor was very aggressively pushing the CTL technology and that the environmental community and the farmers were generally opposed to the state spending money in this area. Discussions with two members of the environmental community corroborated this comment. Combination programs for coal and biomass are suggested to alter this dynamic and to bring these important industries together.

North Dakota

Discussions with state officials indicate that there are existing incentives and pending legislation that would be applicable to, but not targeted directly at, CTL development. These include:

- Programs to create and distribute loan and grant funds (Chap.57-62)
- Plant siting directions (49-22)
- Tax exemptions and rate reductions (HB 1268).

In 1987 North Dakota created a Lignite Research, Development and Marketing Program, which was funded by 10 cents/ton from its coal severance tax. Funds from this program could be used for CTL projects.

VIII.D. Integrating the Strategic Petroleum Reserve and FT Fuels

The Strategic Petroleum Reserve (SPR) is the world's largest supply of emergency crude oil. The taxpayer-funded, federally-owned crude oil is stored in huge underground salt caverns along the coastline of the Gulf of Mexico in Texas and Louisiana. Withdrawing crude oil from the SPR requires Presidential approval under the authorities of the Energy Policy and Conservation Act of 1975. In the event of an energy emergency, SPR oil is distributed to refineries by competitive sale. The SPR has been used for emergency purposes only twice (during Operation Desert Storm in 1991 and after Hurricane Katrina in 2005).

President Ford signed the Energy Policy and Conservation Act (EPCA) on December 22, 1975. The legislation declared it to be U.S. policy to establish a reserve of up to 1 billion barrels of crude oil. The Gulf of Mexico region was a logical choice for oil storage sites. More than 500 salt domes are concentrated along the coast. It is also the location of many U.S. refineries and distribution points for tankers, barges and pipelines. On July 21, 1977, the first oil -- approximately 412,000 barrels of Saudi Arabian light crude -- was delivered to the SPR.

Current Status

The SPR currently has the capacity to hold 727 million barrels. It is the largest emergency oil stockpile in the world. Together, the facilities and crude oil represent a more than $21 billion investment in energy security ($4 billion for facilities and $17 billion for crude oil).

Filling the SPR was suspended in 1995 to devote budget resources to refurbishing equipment and extending the life of the complex through at least 2025. In 1999 fill was resumed in a joint initiative between the Department of Energy and the Department of Interior to supply royalty oil from Federal offshore tracts to the Strategic Petroleum Reserve.

The Energy Policy Act of 2005 directed the Secretary of Energy to fill the SPR to its authorized one billion barrel capacity. This will require DOE to complete proceedings to select sites necessary to expand the SPR to one billion barrels. The DOE intends to expand existing SPR storage sites (Big Hill, TX; Bayou Choctaw, LA; and West Hackberry, LA) and develop one new storage site.

Emergency Drawdown History

In January 1991, coinciding with the Iraqi invasion of Kuwait, President George H.W. Bush ordered the first-ever emergency drawdown of the SPR. Thirty-four million barrels of crude oil were involved. The SPR's second emergency drawdown occurred after Hurricane Katrina. There was massive damage to the oil production facilities, terminals, pipelines, and refineries along the Gulf regions of Mississippi and Louisiana in late August 2005. All Gulf of Mexico production (about 25% of domestic production) was shut in initially. In September 2005, President George W. Bush directed the Secretary of Energy to sell crude oil from the SPR, and DOE sold 11 million barrels.

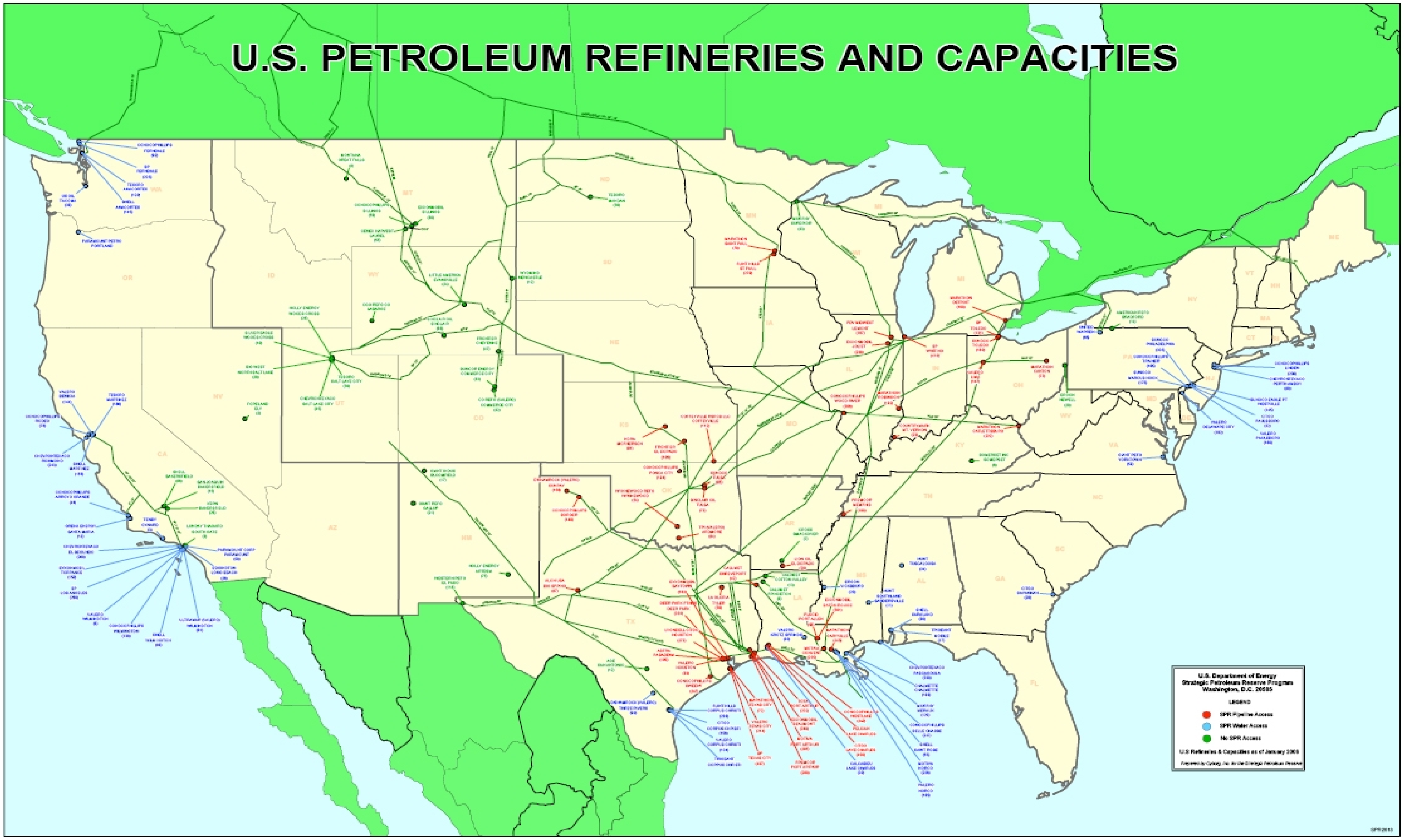
Infrastructure: Cavern storage, Pipelines, Refineries

Emergency crude oil is stored in the Strategic Petroleum Reserve in salt caverns. Created deep within the massive salt deposits that underlie most of the Texas and Louisiana coastline, the caverns offer the best security and are the most affordable means of storage.

Storage locations along the Gulf Coast were selected because they provide a flexible means for connecting to the U.S. commercial oil transport network. Strategic Reserve oil can be distributed through interstate pipelines to nearly half of the Nation's oil refineries or loaded into ships or barges for transport to other refineries – see Figure VIII-2.

SPR caverns range in size from 6 to 35 million barrels in capacity; a typical cavern holds 10 million barrels and is cylindrical in shape with a diameter of 200 feet and a height of 2,000 feet. The Reserve contains 62 of these huge underground caverns.

Figure VIII-2



Northeast Home Heating Oil Reserve Added in 2000

The Northeast Home Heating Oil Reserve is a 2-million barrel supply of emergency fuel oil for homes and businesses in the northeast United States. Established in 2000, the Heating Oil Reserve is an "emergency buffer" that can supplement commercial fuel supplies should the heavily oil-dependent region be hit by a severe heating oil supply disruption. Of the 7.7 million households in the United States that use heating oil to heat their homes, 5.3 million households or roughly 69 percent reside in the Northeast region of the country -- making this area especially vulnerable to fuel oil disruptions.

On July 10, 2000, President Clinton established a 2 million barrel home heating oil component of the Strategic Petroleum Reserve in the Northeast. The intent was to create a buffer large enough to allow commercial companies to compensate for interruptions in supply or severe winter weather. Immediately after the President's July 2000, directive, the Energy Department, acting through the Defense Energy Support Center, issued a solicitation to exchange crude oil from the Strategic Petroleum Reserve for two million barrels of distillate heating oil stocks and for storage facilities in the Northeast. An exchange using Strategic Petroleum Reserve crude oil was chosen because no appropriated funding was available to create the heating oil reserve.

President George W. Bush reinforced the value of the Heating Oil Reserve. In March 2001, the Bush Administration formally notified Congress that it would establish the Reserve as a permanent part of America's energy readiness effort, separate from the Strategic Petroleum Reserve. In May 2001 President Bush issued his National Energy Policy which again endorsed the Reserve as a way to help ensure adequate supplies of heating oil in the event of colder than normal winters.

The original locations of the storage sites were Woodbridge, NJ, and New Haven, CT. In August 2001, the Energy Department approved the relocation of 250,000 barrels of the emergency heating oil inventory to a commercial terminal in Providence, Rhode Island, to extend the distribution capabilities into the Boston area with additional truck and marine loading options.

Advantages of FT Fuel in SPR

The expanded Strategic Petroleum Reserve with both crude oil and heating oil (the Northeast Home Heating Oil Reserve) is an excellent model for understanding the unique role of FT liquid transportation fuels:

1. FT fuels have superior characteristics for long-term storage. These fuels have a multi-year shelf life, and a stockpile of FT fuel is an ideal complement to either Federal or state emergency plans. The fuel is usable without further refining for use by first responders.

2. FT plants will be more geographically diverse. FT plants can be located in more states than existing refineries, but convenient to the transportation infrastructure including pipelines and inland waterways.

Recommendations for Integration of the FT Fuel Industry With the SPR

As was done in the case of the emergency heating oil inventory use of commercial distribution terminals, select plant sites could be designated SPR sites. In addition, States could purchase FT fuels and establish their own emergency stockpiles for use by first responders.

The expansion of the SPR under EPAct 2005 should consider using at least 25% (250 million barrels) of FT fuels in the inventory. The Northeast Home Heating Oil Reserve set a useful precedent for use of existing crude assets to be sold to generate the funds to purchase FT fuels under long term contracts.